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July 16, 2014

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Oregon Public Utilities Commission
Attention: Filing Center
3930 Fairview Industrial Drive SE
Salem, OR 97302-1166

RE: **UE 283 PGE 2015 General Rate Case**

Attention: Filing Center

Enclosed for filing in the captioned docket are an original and five copies of:

Reply Testimony of Portland General Electric Company:

- **PGE/1600**
- **PGE/1700**
- **PGE/1800**
- **PGE/1900**
- **PGE/2000**
- **PGE/2100**

Also enclosed are an original and three copies of:

- **Exhibits on CD (non-confidential portions)**
- **Exhibits on CD (confidential portions)**
- **Work Papers on CD (non-confidential portions)**
- **Work Papers on CD (confidential portions)**

These documents are being served upon the UE 283 service list.

This document is being filed by electronic mail with the Filing Center. An extra copy of the cover letter is enclosed. Please date stamp the extra copy and return to me in the envelope provided.

Thank you in advance for your assistance. If you have any questions or require further information, please call Rob Macfarlane at (503) 464-8954. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

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Before the Public Utility Commission

of the State of Oregon

UE 283
General Rate Case Filing

Portland General Electric Company

Reply Testimony and Exhibits

July 16, 2014

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **UE 283 PORTLAND GENERAL ELECTRIC REPLY TESTIMONY,** by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 283.

DATED at Portland, Oregon, this 16th day of July 2014.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Jay Tinker
Christopher A. Liddle

July 16, 2014

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I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Jay Tinker. I am the Director of Rates and Regulatory Affairs at PGE.

My name is Chris Liddle. I am a Manager of Regulatory Affairs at PGE.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the policy issues raised by other parties in this proceeding. We also introduce other PGE testimony that addresses the remaining unresolved issues in UE 283.

Q. How is your testimony organized?

A. In this section, we provide an overview of this rate case, comparing the initial filing to PGE's revised request based on updates and stipulations. In the next section, we respond to the concerns raised by other parties regarding PGE's proposal to establish a practice of "carving out" renewable resources from our Power Cost Adjustment Mechanism (PCAM) by removing the effect of renewable resources and passing the incremental benefits and costs of those resources through the Renewable Resources Automatic Adjustment Clause tariff (RAC, Schedule 122). We then address the Citizens' Utility Board of Oregon's (CUB) position that energy efficiency is a marginal resource and should be included in the marginal cost of service study. Next, we respond to the Oregon Public Utility Commission Staff's (OPUC Staff or Staff) and Industrial Customers of Northwest Utilities' (ICNU) testimony regarding PGE's proposal to acquire 10% of the Boardman Coal Plant (Boardman) from the Power Resources Cooperative (PRC). In the final section, we provide our qualifications.

Q. Please summarize your filing in UE 283.

A. On February 13, 2014, PGE filed its UE 283 general rate proceeding, which requested rate changes based on three separate components:

- Base business (including power costs) with a revenue change of approximately $12.5 million.
- Base business with customer credits of approximately ($16.5) million.
- Base business, customer credits, and two generating plants of approximately $81.5 million.

Because this case is largely driven by the two new generating plants (Port Westward 2 and the Tucannon River Wind Farm), PGE endeavored to limit the price change from other factors. We accomplished this by:

- Implementing significant cost savings and efficiencies (see PGE Exhibit 100).
- Offsetting the rate increase with credits primarily derived from PGE's litigation against the US Department of Energy's failure to fulfill its contractual obligation to remove spent fuel storage from PGE's Trojan site (see PGE Exhibit 300).
- Holding PGE's 2015 budget as close as possible to the costs that are currently in PGE's retail rates as established by Commission Order No. 13-459 in Docket No. UE 262 (see PGE Exhibit 300).

To support our case, we submitted 418 pages of direct testimony, 17 pages of supplemental testimony, and 99 exhibits. Additionally, in support of our case, PGE submitted two disks with numerous electronic files of work papers, responded to over 700 data requests, held workshops to discuss PGE operations, and participated in settlement meetings. In addition, we offer more information in PGE's Reply testimony. In total, the information in these documents justifies PGE's operations as quantified in our 2015 test year.

Q. What is the current status of the UE 283 proceeding?

A. PGE and other parties held settlement discussions on May 20 and 23 and on July 7, 8, and 11. During those meetings the parties settled a number of issues. We also held settlement discussions in Docket No. UE 286, which addresses the bifurcated power costs for the 2015 test year and settled a number of power cost issues as well. Based on those agreements, partial stipulations are being prepared for filing with the Commission, which, in conjunction with PGE's July 15 NVPC filing, will adjust PGE's revenue requirement as follows:

- Reduced revenue requirement by approximately $4.1 million based on power costs.
- Reduced revenue requirement by approximately $27.0 million based on non-power costs.

Q. In their opening testimony, Staff stated that they were still reviewing information regarding certain PGE's costs. Do you have any concerns regarding their position?

A. Yes. In several instances, Staff stated that they were still reviewing information and had not finalized their positions on PGE's costs. In reply, PGE notes that: 1) we had responded to over 500 data requests before Staff's testimony was due, not including numerous sub-parts and supplemental responses, and 2) the approved UE 283 schedule allowed as much, if not more, time compared to previous general rate cases for which to complete their analyses. PGE finds this unprecedented approach counter to the long-established Commission process in contested cases and it unfairly compromises PGE's (and other parties') ability to respond to Staff testimony. We hope that this was the result of one-time events during this proceeding and look forward to working with Staff to help prevent a recurrence.

Q. What other Reply Testimony is PGE submitting?

A. The following PGE testimony responds to unresolved issues in the following areas:

- 1700 – Revenue Requirement
- 1800 – Port Westward 2 and Tucannon River Wind Farm
- 1900 – Taxes
- 2000 – Return on Equity
- 2100 – Pricing

II. Renewable Portfolio Standard (RPS) Carve-Out

Q. What is the RPS Carve Out?

A. It is PGE's proposal to establish a practice of "carving out" renewable resources from the Power Cost Adjustment Mechanism (PCAM) and passing the incremental benefits and costs of those resources through the Renewable Resources Automatic Adjustment Clause tariff ("RAC", Schedule 122).

Q. Is PGE's RPS Carve Out proposal consistent with the intent of Senate Bill 838?

A. Yes. As noted in PGE's opening testimony (PGE Exhibit 500, Section VI), Senate Bill 838 (SB 838) states:

> "… all prudently incurred costs associated with the compliance with a renewable portfolio standard are recoverable in the rates of an electric company…"

CUB agrees[1] that SB 838 states that a utility should be allowed to recovery prudently incurred costs.

Q. Does PGE claim that SB 838 guarantees recovery of the costs associated with RPS compliant resources?

A. No. Nor is PGE requesting such treatment. The true costs of owning/operating renewables go well beyond their impact on NVPC. PGE is not seeking recovery related to variances in operating expenses. PGE is seeking the opportunity to recover prudently incurred power costs and Production Tax Credits (PTCs) and also to return additional value (reduced power costs or greater PTCs) to customers.

Q. Does the existing regulatory framework allow for recovery of such prudently incurred costs?

[1] CUB/100, Jenks-McGovern/12, Lines 6 - 7

A. No. As discussed in PGE Exhibit 500, Section VI, the existing regulatory framework only provides for an estimate through a general rate case or annual power cost update (AUT) filing. Forecasts vary significantly from actuals for RPS-compliant resources (predominantly wind) as demonstrated in PGE Exhibits 1601, 1602C, 1603, and 1604C. This issue will be exacerbated as additional renewable resources, such as the Tucannon River Wind Farm, are added to PGE's portfolio. Further, the PCAM does not allow PGE recovery of all prudently incurred costs due to the deadbands, earnings test and sharing, which we discuss in more detail below. PTCs are not contemplated by either the AUT[2] or PCAM, with recovery only updated during a general rate case.

Q. Is Staff correct that PGE's proposal is contrary to the intent of Senate Bill 838?

A. No. Staff's claim appears to be based on PGE's proposal to incorporate the RPS Carve Out in Schedule 122, the RAC. The RPS Carve Out could just as easily be included in a different schedule such as Schedule 126 (PCAM) or an entirely new schedule. As discussed above, SB 838 is very clear that prudently incurred costs are recoverable; the RPS Carve Out provides the opportunity to recover those costs and can be incorporated in a different schedule.

Q. Do CUB and ICNU have the same misconception?

A. Yes. ICNU similarly asserts that SB 838 provided for an automatic adjustment clause for "the costs to construct or otherwise acquire renewable resources and for associated transmission" and therefore "it should be inferred that no other costs, including variable power and production tax credit costs, should receive such treatment within the context of

[2] Staff incorrectly notes that PTCs are a part of the AUT process (Staff/1100, Bracken/4, footnote 2). Rather, they are included in customer prices as part of a general rate case proceeding or RAC filing.

SB 838."[3] CUB makes a similar claim. PGE is not suggesting that the automatic adjustment clause described by SB 838 was intended to provide for recovery of variances related to RPS-compliant resources. However, SB 838 does provide for recovery of prudently incurred costs and PGE could just as easily use a schedule other than the RAC to implement the RPS Carve Out.

Q. Does SB 838 state that prudently incurred costs should be recovered through the "normal ratemaking process" as CUB and ICNU suggest?

A. No, SB 838 is not explicit in how prudently incurred costs should be recovered. It does, however, provide for the opportunity to recover prudently incurred costs, which is currently not afforded to PGE in the existing regulatory framework. PGE's proposal would remedy that.

Q. Please explain the misconception parties have regarding how PGE projects power costs and operates its system.

A. PGE's MONET model dispatches resources to minimize power costs, not to meet load. In other words, if load has been met but one or more of PGE's plants are "in the money" (marginal cost is less than marginal revenue), PGE will dispatch the plant(s) to reduce power costs. This is part of the "net" in net variable power costs.

The misconception parties seem to have is that, for example, a wind farm produces 10 MWh less than it was expected to for an hour that PGE re-dispatches its plant(s) (for example, a gas plant as used in Staff's examples) and the "cost" of doing so is the marginal cost of that plant as opposed to the market price. The thought process should not stop there. If PGE re-dispatched a plant to fill the deficit created by the wind resource and that gas plant was in the money, the opportunity cost is the difference between marginal cost of the

[3] ICNU/100, Mullins/6

gas plant and the market price. In other words, because wind was deficit, PGE was unable to take advantage of an opportunity to reduce NVPC by selling the 10 MWh of the gas plant's output into the market. Thus, the true cost of the wind deficit is the market price.

Alternatively, if the market truly is the lowest cost option (i.e., the market price is lower than the marginal cost of generation for the hour in our example), PGE would go to market and again the cost to fill the deficit is the market price.

Q. Does this address parties' issue regarding power "value" and power "cost"?

A. Yes. CUB and Staff claim that a flaw with PGE's proposal is that it is putting a "value" on renewables generation rather than a "cost". This is a distinction without a difference. As explained above, PGE economically dispatches its plants. If renewables are deficit, the cost to replace that power is the market price. If renewables are surplus, the surplus is sold at the market price and reduces power costs.

Q. Should net variable power costs (NVPC) associated with RPS-compliant resources be subject to the PCAM design criteria described in Order Nos. 07-015/12-493 as ICNU suggests?[4]

A. No. For the reasons stated at the beginning of this section, RPS-compliant resources should not be subject to the same design criteria. Specifically, recovery of prudently incurred costs is prevented by subjecting RPS-related power cost variances to:

1) asymmetrical deadbands where, if RPS-compliant resources have greater costs than projected, those costs are not passed on until they are of substantial size (i.e., greater than $30 million, or about 15% of PGE's net income),
2) cost sharing where PGE has significant prudently incurred costs unrecovered, and

[4] ICNU/100, Mullins/7

3) an earnings test where regardless of prudence of costs associated with RPS-compliant resources if PGE's earnings are within a particular range, PGE is prevented from recovering these prudently incurred costs.

It is also worth emphasizing that these same limitations prevent PGE from providing the additional benefits associated with renewable resources to customers.

Q. Will the PCAM continue to operate in the same manner following implementation of the RPS Carve Out?

A. Yes. The PCAM will continue to operate in the same manner; employing deadbands, an earnings test, and sharing on the non-RPS portion of PGE's net variable power costs.

Q. Please explain how the RPS Carve Out and PCAM would interact.

A. As noted in PGE Exhibit 500, PGE will continue to make annual net variable power cost filings (Annual Update Tariff, or "AUT"). PGE's proposed RPS Carve Out would not change this. Consistent with the methodology used to determine the amount subject to the RPS Carve Out (i.e., both the forecast and actuals), PGE would include an adjustment in the PCAM calculation to remove both the forecast and actual renewables power costs. PGE provided examples of this calculation in PGE's Response to OPUC Data Request No. 475 (see PGE Exhibits 1605 and 1606C). Following this approach: (1) removes the possibility for double-counting (i.e., applying both the PCAM and RPS Carve Out to the same underlying costs) and (2) enables the PCAM to continue to operate in the same manner as always on the non-renewable portion of PGE's power costs.

A. CUB's Remaining Issues

Q. Please respond to CUB's assertion that PGE's return on rate base is tied to the risk of managing the asset.[5]

A. CUB's interpretation is too narrow. The authorized return on equity is an opportunity for PGE to earn a return commensurate with its risks. However, PGE's risks are not isolated to the operation of its plants.

Q. Is the relative proportion of capital and fuel cost relevant?[6]

A. No. In complying with the Renewable Portfolio Standard, PGE invested in the least cost, least risk renewable resources. Those funds came from, in part, equity investors who require the opportunity to earn a return on their investment. The proportion of this investment to the amount of fuel cost is irrelevant. PGE was unable to find any references in the areas of regulation, financial markets, or academia to a "risk / rate base ratio". As such, the Commission should disregard this argument from CUB.

Q. Does CUB's discussion of ratemaking practices and the timing of rate changes taking effect have any bearing on PGE's proposed RPS Carve Out proposal?

A. No. This portion of CUB's testimony[7] seems to just state facts and opinions regarding how the timing of rate effective dates has evolved over time, without any testimony relating this to PGE's proposal. PGE is appreciative of CUB's support of prudent investments in RPS-compliant resources and timely inclusion of their related capital and operating costs in customers' prices through the existing RAC.

Q. Please respond to CUB's comparison of wind variability to hydro variability.

[5] CUB/100, Jenks-McGovern/16
[6] Id
[7] CUB/100, Jenks-McGovern/13 - 15

A. CUB claims PGE has not demonstrated that the risks associated with wind variability are greater than those of hydro.[8] As stated previously, SB 838 allows for recovery of prudently incurred costs associated with RPS compliance and the existing regulatory framework does not allow for this. The statute does not require a risk comparison between RPS-compliant resources and non-RPS resources.[9] Further, PGE has provided substantial evidence in support of its request. In particular, PGE has provided hypothetical examples of how the RPS Carve Out would have worked in prior periods (see PGE Exhibits 1601, 1602C, 1603, and 1604C). Staff Exhibit 1100, page 13, Table 2 summarizes the magnitude of the impact.

Q. Please address CUB's concerns regarding the continued viability of PGE's proposal should PGE self-integrate.

A. As demonstrated through the discovery process[10] and as discussed with parties during a workshop on April 25, inclusion of integration costs is limited at this time to BPA Variable Energy Resource Balancing Service (VERBS). This is easily quantifiable in the forecast (it has a line item in PGE's MONET model) and in actuals (PGE can easily track invoices from and payments to BPA). As noted in PGE's response to OPUC Data Request No. 416 (see Staff Exhibit 1103, page 2), PGE is open to input regarding how the mechanism should function when PGE self-integrates in whole or in part. In the meantime, PGE's proposal is based on BPA VERBS only, leaving any other prudently incurred cost variances associated with self-integration in the PCAM.

B. ICNU's Remaining Issues

Q. Does ICNU raise issues with PGE's proposal?

[8] CUB/100, Jenks-McGovern/16 - 17
[9] PGE notes that 50MWa of low impact hydro and certain relatively minor hydro upgrades help PGE meet its RPS requirement.
[10] PGE's response to OPUC Data Request No. 416

A. Yes, ICNU identifies three supposed "flaws" with PGE's proposal: 1) it includes market prices, 2) it is not possible to isolate the variability of individual resources from PGE's portfolio, and 3) system re-dispatch associated with wind cannot be accurately measured.

Q. Please discuss the validity of ICNU's concerns with using market prices in PGE's proposal.

A. ICNU claims "market prices...have nothing to do with RPS compliance." This is counter to what SB 838 states regarding recovery of prudently incurred costs. Wind resources, for example, have minimal variable cost, which means they reduce NVPC. To the extent actual wind generation does not match the forecast, PGE goes to market to either purchase the deficit or sell the surplus. The result is a net variable power <u>cost</u>. ICNU's concerns seem to be related to a lack of understanding of how PGE forecasts NVPC in MONET and how PGE operates its resource portfolio – specifically, MONET and PGE's actual operations dispatch based on economics, not only to meet load. This was addressed earlier in our testimony.

Q. Please discuss the validity of ICNU's assertion that it is not possible to isolate the variability of individual resources from PGE's portfolio.

A. ICNU claims that it is not possible to isolate the variability of individual resources from PGE's resource portfolio without ignoring the diversification benefits that PGE receives as a result of its portfolio. To properly frame this concern, consider that PGE's proposal would not change the amount of NVPC variance in a given year -- that would be the same regardless – rather, PGE seeks to identify the variances associated with RPS-compliant resources and subject them to the RPS Carve Out while leaving the remainder to the PCAM. ICNU provides no support for their position other than a strained comparison to a stock portfolio. PGE has proposed a methodology to identify variances related to RPS-compliant resources. Staff has proposed four methodologies to identify variances related to RPS-compliant resources. Further, PGE agrees with Staff's sentiment that "...there are methods that can be used to reasonably approximate the variance attributable to RPS resources...."[11]

Q. Please elaborate on the market price issue and discuss your proposed remedy.

A. ICNU, CUB and Staff note that PGE's proposed methodology would yield a power cost variance in hours where projected and actual RPS generation are equivalent but market price varies. In examining 2011 through 2013, PGE found that in less than 0.2% of hours were actual generation and projected generation equivalent for PGE's Biglow Canyon wind farm. To alleviate concerns regarding this issue, PGE proposes to alter its methodology to yield zero power cost variance in hours where projected and actual generation are equivalent. PGE would also consider applying a similar methodology that set the power cost variance to zero when the difference between forecasted and actual generation lies within a narrow range.

Q. Please discuss ICNU's concerns with PGE's ability to isolate the variability of individual resources in PGE's proposal.

A. ICNU claims that isolating system re-dispatch associated with wind resource variance cannot be accurately measured. The same context we provide on the prior page applies. Again, ICNU offers no evidence to support their claim and to the contrary, both PGE and Staff have provided methodologies for reasonably identifying prudently incurred costs.

Q. Please discuss ICNU's support for its claims regarding diversity of PGE's portfolio.

A. ICNU attempts to illustrate its point by comparing PGE's resource portfolio to a portfolio of Fortune 500 stocks. ICNU compares PGE's proposal to requesting a deferral mechanism for losses or gains associated with a single stock holding, regardless of how the portfolio is

[11] Staff/1100, Bracken/7, Lines 6-7

performing. At best, this is a strained comparison. As already discussed, SB 838 provides the opportunity to recover prudently incurred costs. The current regulatory structure prevents benefits ("gains" in ICNU's example) from accruing to customers and prevents prudently incurred costs ("losses" in ICNU's example) from being recovered.

Q. Does ICNU raise any other issues regarding SB 838?

A. Yes. ICNU cites UE 246 (Order No. 12-493) claiming that costs associated with RPS-compliant resources should be recovered through the PCAM.[12]

Q. Are ICNU's claims well founded?

A. No. Order No. 12-493 states:

> *While we acknowledge that ORS 469A.120(1) provides for recovery of prudently incurred SB 838 compliance costs, we find it unreasonable to adopt a straight dollar-for-dollar PCAM for the totality of Pacific Power's NPC...*

PGE is not requesting straight dollar-for-dollar recovery of the totality of its net variable power costs as PacifiCorp was when the Commission issued that order. The Commission appropriately acknowledged that SB 838 provides for recovery of prudently incurred costs, and that is what PGE's proposal in this proceeding does.

C. Staff's Remaining Issues & Alternative Methodologies

Q. Staff mentions that certain RPS-compliant resources were part of PGE's portfolio prior to the RPS. Is this relevant?

A. No. Regardless of when they were acquired, renewable resources contribute to PGE's compliance with the Renewable Portfolio Standard. Additionally, with the exception of 50 MWa of low-impact hydro, the other renewable resources fitting Staff's description are

[12] ICNU/100, Mullins/6 - 7

relatively minor (see PGE Exhibit 1607) compared to Biglow Canyon wind farm and Tucannon River Wind Farm.

Q. Please comment on Staff's analysis of three years of recent historical results.

A. The time period examined by Staff is not reflective of the updated wind forecasting methodology which changed beginning in 2014 from the exclusive use of a wind study to the use of a rolling 5-year average of historical actuals. While this may temper the volatility identified by Staff, more importantly, it is anticipated to result in more symmetrical results around the forecast. As noted previously and also noted by Staff,[13] PGE will be required to continue adding renewables to its portfolio to meet the escalating requirements of the RPS, exacerbating the issues with the current regulatory framework's not providing recovery of prudently incurred costs.

Q. Does PGE's proposal contain "major flaws" as Staff suggests?

A. No. In most cases these supposed flaws are based on misconceptions and in one case, though the issue is relatively minor, PGE proposes a remedy.

Q. Does PGE's proposal lead to "questionable outcomes"?

A. No.

Q. Did Staff provide any support for this assertion?

A. Staff identifies a scenario where NVPC are equivalent to the forecast but where the RPS Carve Out would trigger. CUB makes a similar assertion in its testimony[14].

Q. Is this appropriate?

A. Yes. SB 838 allows for recovery of prudently incurred costs associated with RPS compliance and PGE should be granted that opportunity. In Staff's scenario, PGE has

[13] Staff/1100, Bracken/17 - 18
[14] CUB/100, Jenks-McGovern/19

managed its portfolio such that the benefits of the non-RPS portions of its portfolio generated enough value to offset the additional costs associated with the RPS resources. In the context of this example, PGE does not recover its prudently incurred costs nor does it benefit from good management of its portfolio – in other words, the current regulatory framework caps PGE's earnings inappropriately and prevents recovery of prudently incurred costs.

Q. Are Staff's concerns regarding power "cost" and power "value" well founded?

A. No. Please see PGE's discussion of this issue on page 8 of this testimony.

Q. Staff asserts that if power value was included in rates that rates would be much higher.[15] Is that correct?

A. Absolutely not. This is a fundamental misunderstanding. For instance, wind resources reduce net variable power costs. Throughout Staff's tables and examples, wind's cost is at a minimum of $0. This is inaccurate, as wind actually reduces net variable power costs. If wind generation is deficit, PGE goes to market to replace the power. If wind is surplus, we sell the surplus and further reduce power costs.

Q. Staff states that PGE's proposal "incorrectly carve[s] out market price variances."[16] Please explain.

A. Staff identifies the same issue as ICNU regarding a resulting price variance where the forecast and actual generation are equivalent. As noted previously, though this event is extremely rare and therefore de minimis, PGE proposes to remedy this by setting the dollar variance to zero in any hour where the forecast and actual generation are equivalent.

Q. Please address Staff's assertion that variances are purchased on the market.

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[15] Staff/1100, Bracken/22, Lines 15 - 16
[16] Staff/1100, Bracken/23

A. As explained on pages 7 and 8 of this testimony, and noted elsewhere throughout this testimony, PGE dispatches its plants economically, as a function of market prices. Additionally, dispatch differences between forecast and actual that are not related to renewable resources would continue to be handled through the PCAM.

Q. Does PGE agree with Staff that PowerDex is not the correct source for actual market prices?

A. No. As noted in PGE's Response to OPUC Data Request No. 421 (see Staff Exhibit 1103, page 5), PowerDex hourly Mid-Columbia (Mid-C) index, which is a survey-based index supported by reporting of transactions by parties trading at that hub, is the best available hourly market data. This is superior to Staff's proposed volume-weighted PGE transactions because PGE manages renewables variances in the hour-ahead market. Staff's proposal to use pricing for transactions made day(s) or week(s) in advance is not representative of the cost to replace deficit renewables generation or the value of surplus generation sales.

Q. Staff asserts that PGE's proposal could incent PGE to over-collect from customers by modifying various aspects of its forecasts and operation of renewables. Is that the case?

A. While Staff suggests this is possible, they do not explain specifically how this would be accomplished. PGE notes that the methodologies for determining power cost forecasts are reviewed annually by OPUC Staff, CUB, ICNU and sometimes additional parties. PGE also notes that these forecasting methodologies can be changed only during the course of a general rate case proceeding. Finally, PGE's actual results are reviewed by the OPUC Staff and parties through the filing of PGE's annual Results of Operations reports, PCAM filings and, if approved, would be reviewed through annual RPS Carve Out filings (if not part of the PCAM filing). There is no basis on which to suggest PGE's proposal could incent PGE to over-collect from customers and there are numerous processes in place to ensure that type of behavior is not present.

Q. Does Staff agree with PGE's methodology as it relates to integration costs, royalties and PTCs?

A. Yes.

Q. Please summarize Staff's proposed methodologies:

A. Staff's proposed methodologies are as follows:

1) Take the difference between actual and projected renewables generation. If generation was surplus, value it at the last forward curve in MONET. If generation is deficit, value it at the actual price.
2) Identify hours with variances between actual and projected renewables generation. For each of those hours, evaluate thermal generation and assume, wherever possible, that those variances were used to replace deficit or surplus renewable generation. This method only applies to hours where the generation variance is greater than or equal to 20 MWh, otherwise methodology 1 is used.
3) Uses PGE's MONET model to backcast net variable power cost using actuals for renewables generation, market price and gas price. The variance between this backcast and the last MONET forecast for that year is the variance subject to the RPS Carve Out.
4) This is the same as methodology 3, except the only input being changed in the backcast is actual renewables generation.

Staff notes that method 1 is their preferred alternative and as such PGE will focus on it.

Q. What issues does Staff's preferred methodology create?

A. It is worth noting that Staff's preferred methodology is remarkably similar to PGE's proposal. The primary difference is that Staff's method does not consistently use an actual market index for its variance calculations. Instead, it introduces bias to the calculation by using the forward curve used in MONET for hours where actual generation is greater than forecasted generation and using actual market prices where actual generation is less than forecasted generation. Consider a situation where actual market prices for a period of time are either higher or lower across all or most hours due to market conditions (perhaps good or bad hydro, or thermal outages putting upward pressure on market prices, etc.). By relying on two different market prices, Staff's methodology creates biased outcomes. In the scenario where there are thermal outages in the region and market prices are higher, Staff's approach would inappropriately inhibit PGE's ability to return value to customers when renewables generation is surplus. In a scenario where there is downward pressure on prices, Staff's approach would inappropriately cause PGE to return more value to customers than exists. Staff Exhibit 1100, page 29, Table 6 demonstrates the latter in 'Hour 2' where PGE would refund $500 to customers even though the surplus generation was only worth $400 on the market.

The Commission should use one market price index when valuing the variances. PGE proposed using actuals because they best reflect the true cost of replacement power and value of surplus power sales.

Q. Does Staff's preferred methodology "remove market price variance from the calculation to better carve out RPS related NVPC variance"?

A. No. As noted above, Staff's methodology uses market price and forward curves depending on whether generation is surplus or deficit. This mix and match of market price and forward curve introduces bias into the calculation.

Q. Does Staff's preferred methodology solve the "value" issue it purports to?

A. No. Staff emphasizes that their methodology #1 addresses the supposed "value" vs. "cost" issue. As described earlier in this testimony, this is a distinction without difference. To alleviate a related concern, for hours where actual and forecasted generation are equivalent, PGE proposes to set the cost variance to zero.

Q. Please discuss Staff's third claimed benefit – the use of actual PGE power transactions.

A. Staff proposes to use actual PGE wholesale power transaction data, similar to that provided in PGE's response to OPUC Data Request No. 468 (see Staff Exhibit 1103, page 8). The data requested, and the data provided, are for transactions for delivery within one month. PGE's renewable resources (wind and solar in particular) vary hourly. Using pricing for transactions made day(s) or week(s) in advance is not representative of the cost to replace deficit renewables generation or the value of surplus generation sales.

Q. Please discuss PGE's remedy to Staff's fourth issue – PGE's proposal is theoretically inconsistent between owned and contracted resources.

A. Staff's issue centers on PGE's use of hourly data for owned resources and monthly data for contract resources. To address this concern, PGE proposes to use hourly data for all renewable resources.

Q. Is Staff's preferred methodology simpler than PGE's proposal?

A. No. The inputs for the calculations are the same. As noted above, Staff's preference to use hourly data for all resources (owned and contracted) adds complexity to the calculation and the review process. However, PGE proposes to modify its proposal to use hourly data for all resources.

Q. Please comment on the shortcomings Staff identifies with its preferred methodology.

A. Staff notes that its preferred methodology would not alter the PCAM mechanism to account for the RPS Carve Out. This is very concerning as the renewables portion of PGE's generation portfolio would be subject to two mechanisms (the PCAM and RPS Carve Out) which could very well lead to double-counting of collections from or refunds to customers. Without addressing the interplay between the PCAM and RPS Carve Out, Staff's proposal should not be adopted. Staff also notes that their preferred method does not fix or mute the "thermal resource optionality problem." As previously explained, this is not an actual problem but rather a misconception of how PGE manages its portfolio – specifically, the reality that PGE economically dispatches its plants.

Q. Does Staff's methodology #2 solve the supposed problem related to thermal dispatch?

A. No. As explained above, PGE dispatches its plants economically. The cost or value of power to replace deficit renewables generation or sell surplus renewables generation is at the market price.

Q. Would Staff's methodology #2 create unnecessary burden and create complications with evaluating the results?

A. Yes. This proposal is significantly more cumbersome as it requires an hour-by-hour evaluation of not just renewables, but all thermal generation facilities. It attempts to "color code" thermal MWhs and relate them to renewable MWhs. Staff does not provide a methodology for doing so. Presumably recognizing the challenges with doing so, Staff proposes that this methodology be employed only when variances are greater than or equal to 20 MWh. Further, because of the complexity and uncertainty surrounding this proposal, Staff's and parties' ability to review RPS Carve Out filings would be unnecessarily complex.

Q. Please discuss Staff's methodology #3.

A. This proposal attempts to mirror a methodology Staff and PGE proposed in a stipulation in UE 165 regarding hydro variation. It relies on two runs of PGE's MONET model: 1) the final run for an AUT for a test year, and 2) re-running the model for that year with actuals for renewables generation, market prices and gas prices. The difference between these two runs would be the variance subject to the RPS Carve Out.

Q. Please discuss Staff's methodology #4.

A. This methodology is identical to Staff's methodology #3, except that it would only re-run MONET using actuals for renewables generation (and not for market prices and gas prices).

Q. Does PGE support either of these approaches?

A. PGE could possibly support methodology #3. However, additional work would need to be performed to ensure the results of the MONET model using actuals for just three inputs are reasonable. Updating just a single input in MONET as methodology #4 would do, is fraught with problems due to the complexity of the model and interdependencies of its inputs. PGE continues to support its initial proposal (including revisions proposed in this testimony) as it is simple and relies on actual data.

Q. Please summarize your testimony regarding the RPS Carve Out.

A. PGE's proposal is consistent with Senate Bill 838's intent to allow recovery of all prudently incurred costs associated with RPS compliance and leaves the PCAM intact for application to the majority of PGE's net variable power costs. PGE has thoroughly addressed the issues raised by Staff, CUB and ICNU. In two instances, PGE is proposing changes to the RPS Carve Out to address their concerns: 1) using hourly detail for both owned and contracted resources and 2) setting the variance to zero for any hours where forecasted and actual generation are equivalent. Additionally, PGE has provided substantial supporting detail for its proposal including 27 data responses and a workshop. PGE's proposed RPS Carve Out is simple, relies on actual data, allows PGE the opportunity to recover prudently incurred costs, enables PGE to return additional value associated with renewables to customers, and should be adopted by the Commission.

III. Energy Efficiency in Marginal Costs

Q. What policy issue does CUB raise in its reply testimony?

A. CUB raises an issue regarding Senate Bill 838's (SB 838) exemption of customers over one average megawatt and the Energy Trust Of Oregon's (ETO) 18% spending cap on industrial customer energy efficiency.

Q. Please explain the issue.

A. In 2007 with the passage of SB 838, the Oregon Renewable Energy Act, the OPUC was authorized to approve the collection of additional energy efficiency funds from PacifiCorp and PGE customers using less than one average megawatt per year.[17] Customers with annual loads of more than one average megawatt were not required to pay these supplemental energy efficiency charges nor allowed to receive the benefits. To ensure that customers with loads less than one average megawatt were not subsidizing customers with over one average megawatt, PGE, PacifiCorp, the ETO, OPUC Staff, CUB, and ICNU reached an informal agreement that the ETO would not exceed a historical amount of energy efficiency funding for the larger customers' energy efficiency projects. PGE's cap of 18% was an historical average of the ETO energy efficiency payments (under SB 1149) to PGE's customers over one average megawatt, for the three years preceding the passage of SB 838.

Q. Does PacifiCorp have the same cap as PGE?

A. No. PacifiCorp's cap is 27%; again based on an historical average of energy efficiency payments from the ETO to PacifiCorp's industrial customers over one average megawatt. The ETO initially found more industrial energy efficiency opportunities in PacifiCorp's territory than PGE's.

[17] One average megawatt is the definition used in SB1149 based on one meter or a collection of meters within a certain distance from each other.

Q. How close is the ETO to reaching the 18% cap?

A. PGE estimates that the 18% cap will be reached in 2014.

Q. What happens when the cap is reached?

A. The ETO will have two years to scale back payments to PGE's customers over one average megawatt to bring the total spending within the cap.

Q. What are the consequences of the ETO scaling back funding for energy efficiency measures to PGE's customers over one average megawatt?

A. The ETO will limit funding of energy efficiency measures directed to industrial customers. Given that industrial customers currently present a significant portion of cost-effective, energy-efficiency opportunities for the ETO, PGE is concerned that such a response would lower overall PGE acquired energy efficiency. This, in turn, impacts the ETO's ability to meet the targets used in the IRP. PGE's interest is that the ETO pursue all cost-effective energy efficiency; but because of the cap, not all cost effective energy efficiency will be pursued.

Q. Is the ETO concerned about the cap?

A. Yes. In its June 2013 briefing paper for the ETO Board of Directors on ETO energy efficiency programs, the Energy Trust states that given trends in program investment, spending for large customers of PGE will need to be curtailed in 2015 or sooner. The Energy Trust shares PGE's concern that given the funding limitation, the ETO may not be able to secure all cost-effective, energy efficiency from the large customers. In fact, the ETO's 20-year resource assessment shows that more than 50% of energy efficiency savings potential in large sites remains to be acquired. If incentive funding is capped for those sites, the ETO predicts that over the next five years, 8-12 aMW of savings could be lost and 32-48 aMW lost over twenty years.

Q. What does CUB propose?

A. CUB proposes including energy efficiency in the generation marginal cost of service study.

Q. What is PGE's response to the CUB proposal?

A. PGE understands the fairness issues being raised by CUB, including concerns that residential customers are paying disproportionately for energy efficiency. However, CUB's proposal goes beyond traditional marginal cost analysis and it may draw legal challenges. The resulting rate impacts of CUB's proposal are significant for the larger industrial customers and may create an incentive for them to choose direct access.

Q. How does CUB's proposal go beyond traditional marginal cost analysis?

A. Marginal cost analysis is aimed at determining the cost of generating an additional increment of output (marginal generation capacity and marginal energy costs) to meet an increment of load, so that prices can lead to efficient consumption decisions by consumers. Energy efficiency is not a traditional capacity or energy resource.

Q. What does the legislation require?

A. Senate Bill 838, at Chapter 301 Oregon Laws 2007, Section 46 directs the OPUC to ensure that a retail electricity customer with a load greater than one average megawatt is not required to pay an amount that is more than three percent of the customer's electricity cost for the public purpose charge and does not receive any direct benefit from the energy efficiency measures if the costs of the measures are included in rates under SB 838.

Q. Please explain PGE's concern that CUB's proposal may incent large industrial customers to choose direct access.

A. Given the double digit rate impacts of CUB's proposal and the fact that direct access customers do not pay the energy cost to PGE (which is where the marginal cost of energy efficiency as a resource would be included), industrial cost of service customers may be incented to choose long term direct access to avoid the rate increases imposed by CUB's proposal.

Q. What does PGE propose with regard to the cap?

A. Given the statutory prohibition on industrial customers bearing costs associated with SB 838 energy efficiency measures, ratemaking may not be the means to address CUB's concern. The only solution may be a legislative solution. For this reason, PGE does not have a counter proposal to CUB's but offers a willingness to engage with the parties to work on a solution, legislative or otherwise.

IV. Power Resources Cooperative Transaction

Q. Please summarize PGE's proposed transaction with the Power Resources Cooperative.

A. As discussed in PGE Exhibit 1500, PGE's proposes to acquire the PRC's 10% ownership share of Boardman. In 1992, PRC entered into a long-term power purchase agreement (PPA) to sell the output from its 10% ownership share of Boardman to the Turlock Irrigation District (TID). However, PRC has stated that it no longer desires to be in the wholesale power supply business.

PGE is interested in acquiring PRC's ownership share for two reasons:

- Boardman will cease coal-fired operations by the end of 2020. As PGE begins exploring end-of-life options for Boardman, the process will be much simpler and more efficient with the reduced number of co-owners.[18]
- Due to the operating risk premium payment, the transaction with PRC is expected to produce a net benefit for PGE customers.

Q. Have other parties addressed PGE's proposed transaction?

A. Yes. The OPUC Staff (Staff) Exhibit 1200/Crider and Industrial Customers of Northwest Utilities (ICNU) Exhibit 100/Mullins addressed the PRC transaction. We respond to these separately below.

A. OPUC Staff

Q. Please summarize Staff's testimony.

A. Staff describes the components of the transaction and concludes that for all but one of them there is very little or virtually no risk for customers.

Q. For what component does Staff have concerns.

[18] After the acquisition of PRC's ownership share, PGE and Idaho Power Company will be the remaining co-owners.

A. Staff expresses concerns regarding the operating risk premium payment from PRC. Staff's basis is that the operating risk premium payment is the one item in the agreement that is difficult to value since it reflects the potential costs associated with decommissioning the plant.[19] Mr. Crider concludes by stating that "Staff has not yet reached a conclusion on this question. Staff is awaiting further information from the Company regarding the calculation of the operating risk premium."

Q. Does PGE have additional information to provide Staff regarding the operating risk premium payment?

A. No. In addition to our testimony and supporting work papers, PGE has held workshops and has fully responded to all of Staff's Data Requests regarding the operating risk premium payment. In short, there is no additional detail outstanding; PGE has addressed all issues regarding the operating risk premium payment. We believe the premium represents a reasonable net benefit to customers for the potential risk of incremental decommissioning costs.

B. ICNU

Q. Please summarize ICNU's testimony.

A. ICNU claims that PGE will recognize a cash "gain" as a result of the transaction with PRC. Consequently, ICNU recommends that the entire amount of the "gain" related to the PRC transaction be refunded to customers as a one-time credit in 2015.

Q. Do you agree with ICNU's characterization of the PRC payment as a gain?

A. No. PRC does agree to make a lump-sum payment for PGE to assume its 10% ownership share of Boardman with its associated costs, obligations, and liabilities. However, neither

[19] The potential costs specifically refer to those that would be incremental to the total estimated $68 million base decommissioning costs for Boardman.

the total payment, nor any of its components as listed in Table 5 of ICNU Exhibit 100, represent a "realized gain" for PGE.

Q. What do the individual amounts represent?

A. Referring to Table 5 of ICNU Exhibit 100:

- The Boardman Payment represents the calculated net economic value of Boardman, from PRC at closing. There are two elements to this payment:
  - PGE's assumed obligation from PRC for the prepaid coal payment to TID in 2018. This is booked as a liability to TID.
  - The net remaining amount of the Boardman purchase payment. This amount provides a net present value of zero for the 10% Boardman share costs that would be included in PGE's general rate cases and power cost updates (AUT, Schedule 125) filings. In other words, this payment keeps PGE customers whole over the remaining life of the plant (i.e., 2015 through 2020) by offsetting future costs to operate and maintain the incremental share.
- The Operating Risk Premium compensates customers for the risk that actual decommissioning costs exceed the base amount due to potential changes in environmental regulation, increased remediation costs, decreased salvage value, and the retention plan associated with maintaining an adequate number of skilled staff at the plant.
- The 2011 PPA Settlement allows PRC to financially settle a 2011 PPA for power delivered to PGE's system, priced at Mid-C Index, during 2019 and 2020. Because PRC will no longer be able to fulfill the transaction in 2018 and 2019, the financial

settlement ensures that PGE customers receive the full benefit of the 2011 PPA transaction with PRC.

Q. Can you summarize the common nature of these amounts?

A. In all instances, these amounts represent cash flows to appropriately match the costs and benefits associated with the additional 10% of the plant. Although PRC is required to pay the amounts up front to close the transaction, the payments should be timed to match the incurrence of their associated costs. Therefore, these payments represent cash flows, not gains.

C. Transaction Update

Q. In PGE Exhibit 1500, you stated that certain components of the transaction are subject to true-up. Do you have any updates to report at this time?

A. Although the transaction is still under negotiation, we believe that the adjustments currently under discussion will have minimal effect. PGE Exhibit 1608C provides the current estimate of the transaction and a comparison to PGE's original estimate – see columns (F), (G), and (H). Additional detail for this calculation is provided in confidential work papers to this testimony.

V. Qualifications

Q. Mr. Tinker, please state your qualifications.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since 1996.

Q. Mr. Liddle, please state your qualifications.

A. I received a Bachelor of Science degree in Business Administration with a finance emphasis from the University of Oregon and a Master of Business Administration degree from Portland State University. I have been employed at PGE since 2005, working in various departments including Corporate Finance, Investor Relations, and Utility Asset Management. I have worked in the Rates and Regulatory Affairs department since 2008.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1601	PGE's Response to OPUC Data Request No. 471
1602C	Confidential Attachments to PGE's Response to OPUC Data Request No. 471
1603	PGE's Response to ICNU Data Request No. 079
1604C	Confidential Attachments to PGE's Response to ICNU Data Request No. 079
1605	PGE's Response to OPUC Data Request No. 475
1606C	Confidential Attachments to PGE's Response to OPUC Data Request No. 475
1607	PGE's Response to OPUC Data Request No. 411
1608C	PRC Updated Regulatory Effects

May 27, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 471
Dated May 13, 2014

Request:

Please update ICNU Data Response No. 079 to include calendar years 2009 and 2010 in addition to calendar years 2011, 2012 and 2013.

Response:

Per discussion with OPUC Staff, PGE is providing 2011 and 2012 RPS Carve Out examples using all eligible renewable resources, and 2009 and 2010 using just the Biglow Canyon wind farm (Biglow).

Attachment 471-A contains the following RPS Carve Out examples using:

- 2011 forecast and actual data
- 2012 forecast and actual data
- 2013 forecast and actual data

For 2011 and 2012, PGE is using the forecast generation for 2015 as the baseline for Biglow, because it is based on the improved 5-year rolling average methodology. The 2013 example is a revised version to the example provided in PGE's Response to ICNU Data Request No. 079. For details on the revisions, please see PGE's Supplemental Response to ICNU Data Request No. 079.

For 2009 and 2010, PGE is providing an analysis using just the variance for PGE's Biglow, which represents the majority of PGE's renewables. Attachment 471-B provides the analyses for 2009, 2010 and revised versions of the 2011 and 2012 Biglow Only examples provided in PGE's Response to ICNU Data Request No. 079. For details on the revisions, please see PGE's Supplemental Response to ICNU Data Request No. 079.

The supporting data are included in the referenced files. Please note that in addition to MWh forecast variances, price variances played a significant role in the results for these two years.

Attachment 471-A and 471-B are confidential and subject to Protective Order No. 14-043.

UE 283

Attachment 471-A

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format Only

2011, 2012 and 2013 RPS Carve Out Examples

UE 283

Attachment 471-B

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format Only

2009, 2010, 2011 and 2012 RPS Carve Out Examples
(Biglow Only)

Exhibit 1602C
Confidential

April 22, 2014

TO: Bradley Van Cleve
Irion Sanger
Bradley Mullins

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to ICNU Data Request No. 079
Dated April 8, 2014

Request:

Refer to PGE Exhibit 500 at 43-47. Beginning with the first year that PGE's renewable adjustment clause tariff (Schedule 122) was effective, and continuing through the period data is available, please provide a breakdown of the forecasted versus actual costs associated with items PGE proposes to include in Schedule 122 as an adjustment to its Results of Operations report (variances in power costs and production tax credits). To the extent possible, please identify known reasons for any differences in costs.

Response:

PGE objects to this request on the basis that it is overly broad and unduly burdensome. Notwithstanding this objection, PGE responds as follows:

Attachment 079-A contains an example of the RPS Carve Out using 2013 forecast and actual data. The supporting data is included in the referenced files.

For 2011 and 2012, PGE is providing an analysis using just the variance for PGE's Biglow Canyon wind farm, which represents the majority of PGE's renewables portfolio. Additionally, PGE is using the forecasted generation for 2015 as the baseline, because it is based on the improved 5-year rolling average methodology. Please note that in addition to MWh forecast variances, price variances played a significant role in the results for these two years. The 2011 and 2012 analyses are also included in Attachment 079-A.

Attachment 079-A is confidential and subject to Protective Order No. 14-043.

UE 283

Attachment 079-A

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format only

RPS Carve Out Examples

Exhibit 1604C
Confidential

May 27, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 475
Dated May 13, 2014

__Request:__

Please provide the following for every year under the current net variable power cost mechanism:

a. **Power Cost Variance that was subject to deadband and sharing in the PCAM**
b. **RPS carve out variance if the RPS carve out as proposed by the Company had been in place for each year**
c. **NVPC Variance in the PCAM had the RPS carve out as proposed by the Company been in place for each year**
d. **Amount of the NVPC variance subject to sharing in the PCAM had the RPS carve out as proposed by the Company been in place for each year**

Response:

Per discussion with OPUC Staff, PGE has developed full RPS Carve Out examples for 2011, 2012 and 2013. Therefore, PGE provides the following responses on Power Cost Variance (PCV) for the years 2011 – 2013. Please note that the 2013 PCAM has not yet been filed, hence the 2013 example is preliminary and draft.

Attachment 475-A provides a summary of the PCAM and RPS PCV for 2011, 2012 and 2013.

Attachment 475-B provides details for the calculation of the PCV referenced in Attachment 475-A. Attachment 475-A and 475-B are confidential and subject to Protective Order No. 14-043.

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UE 283

Attachment 475-A

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format Only

Summary of the PCAM and RPS PCV for 2011 - 2013

UE 283

Attachment 475-B

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format Only

Details for the Calculation of the PCV

Exhibit 1606C
Confidential

April 23, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 411
Dated April 9, 2014

Request:

What mW amount of renewable resources would PGE have in service January 1, 2015 absent any RPS requirement in Oregon? Provide all workpapers and listing of assumptions in deriving this mW value.

Response:

PGE objects to this request as overly broad, unduly burdensome, calling for speculation, and seeking evidence that is not relevant nor reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving its objections, PGE responds as follows:

PGE cannot determine how many MWs of renewable resources it would have purchased in a "but for" world because of the numerous unquantifiable changes in inputs that it would have to make. PGE has not conducted such an analysis and the number and magnitude of assumptions needed to complete such an analysis would render the results highly doubtful.

PGE did contract for renewable energy before any RPS requirement was in effect in Oregon (Senate Bill 838 was passed in 2007) and it is likely that these projects would still be in service on January 1, 2015 even without the RPS requirements. A list of projects is provided below:

- PPM Klondike II
- Vansycle
- Low-impact hydro / hydro efficiency upgrades: Round Butte, Sullivan, Faraday, North Fork, River Mill

Exhibit 1608C
Confidential

Before the Public Utility Commission

of the State of Oregon

UE 283

General Rate Case Filing

Portland General Electric Company

Reply Testimony and Exhibits

July 16, 2014

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **UE 283 PORTLAND GENERAL ELECTRIC REPLY TESTIMONY,** by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 283.

DATED at Portland, Oregon, this 16th day of July 2014.

Patrick G. Hager
Manager, Regulatory Affairs
Portland General Electric Company
121 SW Salmon St., 1WTC0702
Portland, OR 97204
503-464-7580 Telephone
503-464-7651 Fax
patrick.hager@pgn.com

I. Revenue Requirement

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Alex Tooman. I am a project manager for PGE. I am responsible, along with Mr. Macfarlane, for the development of PGE's revenue requirement forecast. In addition, my areas of responsibility include results of operations reporting, power cost adjustment mechanism filings and other regulatory analyses.

My name is Robert Macfarlane. I am also a project manager for PGE. My areas of responsibility include revenue requirement and other regulatory analyses.

Our qualifications were previously provided in PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. Our testimony presents PGE's revised revenue requirements consistent with:

1. PGE's revised load forecast.
2. The settlements with parties reached on May 27, June 8, and June 11 in this case. The settlements resolve PGE's capital structure, cost of debt, plant in-service other than deferred tax assets associated with production tax credits, and most of PGE's 2015 O&M costs.
3. PGE's requested return on equity (ROE) of 10% as initially filed in this case. PGE Exhibit 2000 is the reply testimony of Bente Villadsen, PGE's expert ROE witness.
4. An updated 2015 forecast of net variable power costs (NVPC) consistent with our July 15, 2014 filing and the updated 2015 load forecast. In addition, the NVPC update reflects the reduction of power costs resulting from the terms of a NVPC partial stipulation filed with the Commission in UE 286.
5. The stipulation for the depreciation study filed in UM 1679.

6. The effects of the acquisition of a 10% share of the Boardman coal plant as outlined in PGE Exhibit 1500 and updated in PGE Exhibit 1600.
7. Updates for Port Westward 2 (PW2) and Tucannon River Wind Farm (Tucannon) as outlined in PGE Exhibit 1800.

Q. What is PGE's revised revenue requirement increase in this case?

A. PGE's revised revenue requirement increase in this case is $60.5 million comprised of: a decrease of $28.9 million for the base business, an increase of $49.0 million for PW2, and an increase of $40.4 million for Tucannon. PGE Exhibit 1701 provides the revised revenue requirement increase for the base business, PW2, and Tucannon. The revised revenue requirement increases compare to PGE's initial request[1] of $12.5 million for the base business, $51.4 million for PW2, and $46.7 million for Tucannon. Table 1 below summarizes the revised revenue requirement increase for the base business in this case:

Table 1
($ millions)

	Base
Original Filing	$12.5
June Load Forecast Update	($4.3)
PRC Share of Boardman Non-NVPC	$5.5
UM 1679 Depreciation Update	($11.5)
UE 283 Partial Stipulations	($27.0)
UE 286 NVPC Update	($4.1)
Total	($28.9)

The revised revenue requirement is also the basis for the analysis of prices and rate change impacts provided in PGE Exhibit 2100 (Pricing).

[1] See PGE Exhibit 300

Q. Do the revenue requirements in Table 1 and PGE Exhibit 1701 provide all updates consistent with the settlements to date?

A. No. PGE is still evaluating the property tax effects of the settled changes to rate base and will provide the appropriate update in the near future.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1701	PGE Revised 2015 Revenue Requirement

Portland General Electric Company
2015 Revenue Requirement Summary
Dollars in $000s

	Rev Req	Percent
Total Increase:	60,538	3.50%

	Base Business 2015	PW2	Tucannon	Total Results
	(1)	(2)	(3)	(4)
1 Sales to Consumers	1,705,481	49,050	40,354	1,794,885
2 Sales for Resale	-	-	-	-
3 Other Revenues	24,831	-	-	24,831
4 Total Operating Revenues	1,730,311	49,050	40,354	1,819,716
5 Net Variable Power Costs	589,812	(1,266)	(22,427)	566,119
6 Production O&M (excludes Troja	141,125	1,479	7,470	150,074
7 Trojan O&M	68	-	-	68
8 Transmission O&M	15,028	-	-	15,028
9 Distribution O&M	94,623	-	-	94,623
10 Customer & MBC O&M	69,465	-	-	69,465
11 Uncollectibles Expense	8,016	231	190	8,436
12 OPUC Fees	5,330	153	126	5,609
13 A&G, Ins/Bene., & Gen. Plant	140,073	347	435	140,854
14 Total Operating & Maintenance	1,063,539	944	(14,206)	1,050,277
15 Depreciation	234,808	9,491	23,209	267,508
16 Amortization	32,872	-	-	32,872
17 Property Tax	51,142	1,663	6,943	59,749
18 Payroll Tax	14,033	30	7	14,070
19 Other Taxes	1,835	-	-	1,835
20 Franchise Fees	42,657	1,227	1,009	44,893
21 Utility Income Tax	60,809	11,047	(15,660)	56,195
22 Total Operating Expenses & Tax	1,501,695	24,401	1,302	1,527,398
23 **Utility Operating Income**	228,617	24,648	39,052	292,317
24 **Rate Base**				
25 Avg. Gross Plant	7,276,617	323,227	524,617	8,124,460
26 Avg. Accum. Deprec. / Amort	(3,806,332)	(5,800)	(11,604)	(3,823,736)
27 Avg. Accum. Def Tax	(612,284)	890	(7,300)	(618,694)
28 Avg. Accum. Def ITC	-	-	-	-
29 **Net Utility Plant**	2,858,001	318,316	505,713	3,682,030
30 Misc. Deferred Debits	29,352	-	-	29,352
31 Operating Materials & Fuel	75,103	-	-	75,103
32 Misc. Deferred Credits	(57,240)	-	-	(57,240)
33 Working Cash	55,563	903	48	56,514
34 **Rate Base**	2,960,779	319,219	505,761	3,785,759
35 **Rate of Return**	7.722%			7.722%
36 **Implied Return on Equity**	10.000%			10.000%

	Base Business 2015	PW2	Tucannon	Total Results
	(1)	(2)	(3)	(4)
37 Effective Cost of Debt	5.443%	5.443%	5.443%	5.443%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structur	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.722%	2.722%	2.722%	2.722%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.614%	7.614%	7.614%	7.614%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.949%	39.949%	39.949%	39.949%
47 Bad Debt Rate	0.470%	0.470%	0.470%	0.470%
48 Franchise Fee Rate	2.501%	2.501%	2.501%	2.501%
49 Working Cash Factor	3.700%	3.700%	3.700%	3.700%
50 Gross-Up Factor	1.665	1.665	1.665	1.665
51 ROE Target	10.000%	10.000%	10.000%	10.000%
52 Grossed-Up COC	11.048%	11.048%	11.048%	11.048%
53 OPUC Fee Rate	0.3125%	0.3125%	0.313%	0.313%
Utility Income Taxes				
54 Book Revenues	1,730,311	49,050	40,354	1,819,716
55 Book Expenses	1,440,886	13,354	16,963	1,471,203
56 Interest Deduction	80,578	8,688	13,764	103,029
57 Production Deduction	-	-	-	-
58 Permanent Ms	(20,679)	(645)	(627)	(21,951)
59 Deferred Ms	(58,125)	6,196	71,740	19,811
60 Taxable Income	287,652	21,457	(61,485)	247,624
61 Current State Tax	21,901	1,634	(4,681)	18,854
62 State Tax Credits	(3,009)	-	-	(3,009)
63 Net State Taxes	18,892	1,634	(4,681)	15,845
64 Federal Taxable Income	268,760	19,823	(56,804)	231,779
65 Current Federal Tax	94,066	6,938	(19,881)	81,123
66 Federal Tax Credits	(28,929)	-	(19,757)	(48,686)
67 ITC Amort	-	-	-	-
68 Deferred Taxes	(23,221)	2,475	28,659	7,914
69 Total Income Tax Expense	60,809	11,047	(15,660)	56,195
70 Regulated Net Income	148,039			189,288
71 Check Regulated NI				189,288

PGE Exhibit 1701
Portland General Electric Company
2015 Revenue Requirement - Base Business
Dollars in $000s

										Rev Req	Percent
									Total Increase:	(28,866)	-1.67%
	At Current Rates	June Load Forecast Delta	GRC Change for RROE	Proposed 2015	PRC Non-NVPC	PRC Update Non-NVPC	UM 1679 Depreciation Base	Subtotal	Non-NVPC Adjustments	NVPC Adjustments	Total Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1 Sales to Consumers	1,730,004	4,343	8,153	1,742,500	4,730	793	(11,529)	1,736,493	(26,960)	(4,053)	1,705,481
2 Sales for Resale	-			-				-	-	-	-
3 Other Revenues	23,521			23,521				23,521	1,310	-	24,831
4 Total Operating Revenues	1,753,525		8,153	1,766,021	4,730	793	(11,529)	1,760,014	(25,650)	(4,053)	1,730,311
5 Net Variable Power Costs	593,425			593,425		290		593,715	-	(3,903)	589,812
6 Production O&M (excludes Trojan)	136,508			136,508	4,144	473		141,125	-	-	141,125
7 Trojan O&M	68			68				68	-	-	68
8 Transmission O&M	15,028			15,028				15,028	-	-	15,028
9 Distribution O&M	94,623			94,623				94,623	-	-	94,623
10 Customer & MBC O&M	70,202			70,202				70,202	(737)	-	69,465
11 Uncollectibles Expense	8,650		62	8,712	24	4	(58)	8,682	(116)	(19)	8,016
12 OPUC Fees	5,406		39	5,445	15	2	(36)	5,427	(77)	(13)	5,330
13 A&G, Ins/Bene., & Gen. Plant	149,418			149,418				149,418	(9,345)	-	140,073
14 Total Operating & Maintenance	1,073,328		102	1,073,430	4,182	770	(94)	1,078,288	(10,275)	(3,935)	1,063,539
15 Depreciation	245,908			245,908			(11,100)	234,808	-	-	234,808
16 Amortization	34,100			34,100				34,100	(1,228)	-	32,872
17 Property Tax	51,142			51,142				51,142	-	-	51,142
18 Payroll Tax	14,033			14,033				14,033	-	-	14,033
19 Other Taxes	1,835			1,835				1,835	-	-	1,835
20 Franchise Fees	43,270		313	43,583	118	20	(288)	43,432	(616)	(101)	42,657
21 Utility Income Tax	59,242		4,824	64,067	129	1	(14)	64,182	(3,368)	(5)	60,809
22 Total Operating Expenses & Taxes	1,522,859		5,238	1,528,097	4,429	790	(11,496)	1,521,821	(15,487)	(4,041)	1,501,695
23 **Utility Operating Income**	230,666		7,257	237,923	301	2	(33)	238,193	(10,163)	(12)	228,617
				237,923							228,617
24 **Average Rate Base**											
25 Avg. Gross Plant	7,293,364			7,293,364	3,700			7,297,064	(20,447)	-	7,276,617
26 Avg. Accum. Deprec. / Amort	(3,805,842)			(3,805,842)				(3,805,842)	(490)	-	(3,806,332)
27 Avg. Accum. Def Tax	(579,549)			(579,549)				(579,549)	(32,734)	-	(612,284)
28 Avg. Accum. Def ITC	-			-				-	-	-	-
29 **Avg. Net Utility Plant**	2,907,972		-	2,907,972	3,700	-	-	2,911,672	(53,671)	-	2,858,001
30 Misc. Deferred Debits	30,852			30,852				30,852	(1,500)	-	29,352
31 Operating Materials & Fuel	75,103			75,103				75,103	-	-	75,103
32 Misc. Deferred Credits	(11,740)			(11,740)				(11,740)	(45,500)	-	(57,240)
33 Working Cash	56,346		194	56,540	164	29	(425)	56,307	(573)	(150)	55,563
34 **Average Rate Base**	3,058,533		194	3,058,727	3,864	29	(425)	3,062,195	(101,244)	(150)	2,960,779
35 **Rate of Return**	7.542%			7.779%							7.722%
36 **Implied Return on Equity**	9.526%			10.000%							10.000%

	At Current Rates	June Load Forecast Delta	GRC Change for RROE	Proposed 2015	PRC Non-NVPC	PRC Update Non-NVPC	Depreciation Base	Subtotal	Non-NVPC Adjustments	NVPC Adjustments	Total Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
37 Effective Cost of Debt	5.557%		5.557%	5.557%	5.557%	5.557%	5.557%	5.557%	5.443%	5.443%	5.443%
38 Effective Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.779%		2.779%	2.779%	2.779%	2.779%	2.779%	2.779%	2.722%	2.722%	2.722%
42 Weighted Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.614%		7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%
45 Federal Tax Rate	35.000%		35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.949%		39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%
47 Bad Debt Rate	0.500%		0.500%	0.500%	0.500%	0.500%	0.500%	0.500%	0.470%	0.470%	0.470%
48 Franchise Fee Rate	2.501%		2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%
49 Working Cash Factor	3.700%		3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%
50 Gross-Up Factor	1.665		1.665	1.665	1.665	1.665	1.665	1.665	1.665	1.665	1.665
51 ROE Target	10.000%		10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%
52 Grossed-Up COC	11.105%		11.105%	11.105%	11.105%	11.105%	11.105%	11.105%	11.048%	11.048%	11.048%
53 OPUC Fee Rate	0.3125%		0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.313%	0.313%
Utility Income Taxes											
54 Book Revenues	1,753,525		12,496	1,766,021	4,730	793	(11,529)	1,760,014	(25,650)	(4,053)	1,730,311
55 Book Expenses	1,463,617		414	1,464,031	4,301	789	(11,482)	1,457,639	(12,717)	(4,036)	1,440,886
56 Interest Deduction	84,981		5	84,987	107	1	(12)	85,083	(2,755)	(4)	80,578
57 Production Deduction	-			-				-	-		-
58 Permanent Ms	(20,679)			(20,679)				(20,679)	-		(20,679)
59 Deferred Ms	(26,469)			(26,469)				(26,469)	(31,657)		(58,125)
60 Taxable Income	252,074		12,076	264,151	322	2	(35)	264,440	21,479	(12)	287,652
61 Current State Tax	19,193		919	20,112	24	0	(3)	20,134	1,635	(1)	21,901
62 State Tax Credits	(3,009)			(3,009)				(3,009)	-		(3,009)
63 Net State Taxes	16,183		919	17,103	24	0	(3)	17,125	1,635	(1)	18,892
64 Federal Taxable Income	235,891		11,157	247,048	297	2	(33)	247,315	19,844	(12)	268,760
65 Current Federal Tax	82,562		3,905	86,467	104	1	(11)	86,560	6,945	(4)	94,066
66 Federal Tax Credits	(28,929)			(28,929)				(28,929)	-		(28,929)
67 ITC Amort	-		-	-					-		-
68 Deferred Taxes	(10,574)		0	(10,574)	0	0	0	(10,574)	(12,647)	-	(23,221)
69 Total Income Tax Expense	59,242		4,824	64,067	129	1	(14)	64,182	(4,066)	(5)	60,809
70 Regulated Net Income	145,684			152,936							148,039
71 Check Regulated NI				152,936							148,039

Portland General Electric Company
2015 Revenue Requirement - Port Westward 2
Dollars in $000s

	As Filed (2/13/2014)	DR 437 Update (5/12/2014)	Subtotal	First Settlement Impact	First Settlement Subtotal	Depreciation Study Update Impact	NVPC Adjustments	Total
1 Sales to Consumers	51,371	2,106	53,476	(205)	53,272	(4,990)	769	49,050
2 Sales for Resale	-	-	-		-	-	-	-
3 Other Revenues	-	-	-		-	-	-	-
4 Total Operating Revenues	51,371	2,106	53,476	(205)	53,272	(4,990)	769	49,050
5 Net Variable Power Costs	(1,213)	(792)	(2,006)	-	(2,006)	-	740	(1,266)
6 Production O&M (excludes Trojan)	1,479	-	1,479	-	1,479	-	-	1,479
7 Trojan O&M	-	-	-	-	-	-	-	-
8 Transmission O&M	-	-	-	-	-	-	-	-
9 Distribution O&M	-	-	-	-	-	-	-	-
10 Customer & MBC O&M	-	-	-	-	-	-	-	-
11 Uncollectibles Expense	257	11	267	(1)	250	(23)	4	231
12 OPUC Fees	161	7	167	(1)	166	(16)	2	153
13 A&G, Ins/Bene., & Gen. Plant	347	-	347	-	347	-	-	347
14 Total Operating & Maintenance	1,030	(775)	254	(2)	237	(39)	746	944
15 Depreciation	13,588	749	14,337	-	14,337	(4,846)	-	9,491
16 Amortization	-	-	-	-	-	-	-	-
17 Property Tax	1,434	229	1,663	-	1,663	-	-	1,663
18 Payroll Tax	30	-	30	-	30	-	-	30
19 Other Taxes	-	-	-	-	-	-	-	-
20 Franchise Fees	1,285	53	1,338	(5)	1,332	(125)	19	1,227
21 Utility Income Tax	10,186	855	11,040	(79)	11,040	6	1	11,047
22 Total Operating Expenses & Taxes	27,551	1,111	28,662	(86)	28,639	(5,004)	766	24,401
23 **Utility Operating Income**	23,819	995	24,815	(119)	24,633	14	2	24,648
24 **Average Rate Base**								
25 Avg. Gross Plant	310,417	12,809	323,227	-	323,227	-	-	323,227
26 Avg. Accum. Deprec. / Amort	(6,676)	(346)	(7,023)	-	(7,023)	1,223	-	(5,800)
27 Avg. Accum. Def Tax	1,457	293	1,750	-	1,750	(861)	-	890
29 **Avg. Net Utility Plant**	305,198	12,756	317,954	-	317,954	362	-	318,316
30 Misc. Deferred Debits	-	-	-	-	-	-	-	-
31 Operating Materials & Fuel	-	-	-	-	-	-	-	-
32 Misc. Deferred Credits	-	-	-	-	-	-	-	-
33 Working Cash	1,019	41	1,060	(3)	1,060	(185)	28	903
34 **Average Rate Base**	306,217	12,797	319,015	(3)	319,014	177	28	319,219
35 **Rate of Return**	7.779%		7.779%					7.722%
36 **Implied Return on Equity**	10.000%		10.000%					10.000%

37 Effective Cost of Debt	5.557%	5.557%	5.557%	5.443%	5.443%	5.443%	5.443%	5.443%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.779%	2.779%	2.779%	2.722%	2.722%	2.722%	2.722%	2.722%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%
47 Bad Debt Rate	0.500%	0.500%	0.500%	0.470%	0.470%	0.470%	0.470%	0.470%
48 Franchise Fee Rate	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%
49 Working Cash Factor	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%
50 Gross-Up Factor	1.665	1.665	1.665	1.665	1.665	1.665	1.665	1.665
51 ROE Target	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%
52 Grossed-Up COC	11.105%	11.105%	11.105%	11.048%	11.048%	11.048%	11.048%	11.048%
53 OPUC Fee Rate	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%
Utility Income Taxes								
54 Book Revenues	51,371	2,106	53,476	(205)	53,272	(4,990)	769	49,050
55 Book Expenses	17,366	256	17,621	(7)	17,599	(5,010)	765	13,354
56 Interest Deduction	8,508	356	8,864	(0)	8,682	5	1	8,688
57 Production Deduction	-	-	-	-	-	-	-	-
58 Permanent Ms	-	(645)	(645)	-	(645)	-	-	(645)
59 Deferred Ms	-	1,350	1,350	-	1,350	4,847	-	6,196
60 Taxable Income	25,496	790	26,287	(198)	26,287	(4,832)	2	21,457
61 Current State Tax	1,941	60	2,001	(15)	2,001	(368)	0	1,634
62 State Tax Credits	-	-	-	-	-	-	-	-
63 Net State Taxes	1,941	60	2,001	(15)	2,001	(368)	0	1,634
64 Federal Taxable Income	23,555	730	24,285	(183)	24,285	(4,464)	2	19,823
65 Current Federal Tax	8,244	255	8,500	(64)	8,500	(1,562)	1	6,938
66 Federal Tax Credits	-	-	-	-	-	-	-	-
67 ITC Amort	-	-	-	-	-	-	-	-
68 Deferred Taxes	-	539	539	-	539	1,936	-	2,475
69 Total Income Tax Expense	10,186	855	11,040	(79)	11,040	6	1	11,047
70 Regulated Net Income								
71 Check Regulated NI								

PGE Exhibit 1701
Portland General Electric Company
2015 Revenue Requirement - Tucannon River Wind Farm
Dollars in $000s

	As Filed (2/13/2014)	DR 443 Update (5/12/2014)	Subtotal	First Settlement Impact	First Settlement Subtotal	Depreciation Study Update Impact	NVPC Adjustments	Total
1 Sales to Consumers	46,663	919	47,582	(312)	47,269	(3,320)	(3,595)	40,354
2 Sales for Resale	-	-	-		-	-	-	-
3 Other Revenues	-	-	-		-	-	-	-
4 Total Operating Revenues	46,663	919	47,582	(312)	47,269	(3,320)	(3,595)	40,354
5 Net Variable Power Costs	(16,423)	(2,542)	(18,965)	-	(18,965)	-	(3,462)	(22,427)
6 Production O&M (excludes Trojan)	8,473	(1,003)	7,470	-	7,470	-	-	7,470
7 Trojan O&M	-	-	-	-	-	-	-	-
8 Transmission O&M	-	-	-	-	-	-	-	-
9 Distribution O&M	-	-	-	-	-	-	-	-
10 Customer & MBC O&M	-	-	-	-	-	-	-	-
11 Uncollectibles Expense	233	5	238	(1)	222	(16)	(17)	190
12 OPUC Fees	146	3	149	(1)	148	(10)	(11)	126
13 A&G, Ins/Bene., & Gen. Plant	435	-	435	-	435	-	-	435
14 Total Operating & Maintenance	(7,136)	(3,537)	(10,673)	(2)	(10,690)	(26)	(3,490)	(14,206)
15 Depreciation	23,671	2,876	26,547	-	26,547	(3,338)	-	23,209
16 Amortization	-	-	-	-	-	-	-	-
17 Property Tax	6,943	-	6,943	-	6,943	-	-	6,943
18 Payroll Tax	7	-	7	-	7	-	-	7
19 Other Taxes	-	-	-	-	-	-	-	-
20 Franchise Fees	1,167	23	1,190	(8)	1,182	(83)	(90)	1,009
21 Utility Income Tax	(16,482)	788	(15,694)	(121)	(15,694)	38	(4)	(15,660)
22 Total Operating Expenses & Taxes	8,171	149	8,320	(131)	8,296	(3,409)	(3,585)	1,302
23 **Utility Operating Income**	38,492	770	39,261	(181)	38,974	89	(10)	39,052
24 **Average Rate Base**								
25 Avg. Gross Plant	510,037	14,579	524,617	-	524,617	-	-	524,617
26 Avg. Accum. Deprec. / Amort	(11,834)	(1,534)	(13,368)	-	(13,368)	1,764	-	(11,604)
27 Avg. Accum. Def Tax	(3,660)	(3,154)	(6,815)	-	(6,815)	(485)	-	(7,300)
29 **Avg. Net Utility Plant**	494,543	9,891	504,434	-	504,434	1,279	-	505,713
30 Misc. Deferred Debits	-	-	-	-	-	-	-	-
31 Operating Materials & Fuel	-	-	-	-	-	-	-	-
32 Misc. Deferred Credits	-	-	-	-	-	-	-	-
33 Working Cash	302	6	308	(5)	307	(126)	(133)	48
34 **Average Rate Base**	494,845	9,897	504,742	(5)	504,741	1,152	(133)	505,761
35 **Rate of Return**	7.779%				7.722%			7.722%
36 **Implied Return on Equity**	10.000%				10.000%			10.000%

37 Effective Cost of Debt	5.557%	5.557%	5.557%	5.443%	5.443%	5.443%	5.443%	5.443%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.779%	2.779%	2.779%	2.722%	2.722%	2.722%	2.722%	2.722%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%	7.614%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%	39.949%
47 Bad Debt Rate	0.500%	0.500%	0.500%	0.470%	0.470%	0.470%	0.470%	0.470%
48 Franchise Fee Rate	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%	2.501%
49 Working Cash Factor	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%	3.700%
50 Gross-Up Factor	1.665	1.665	1.665	1.665	1.665	1.665	1.665	1.665
51 ROE Target	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%	10.000%
52 Grossed-Up COC	11.105%	11.105%	11.105%	11.048%	11.048%	11.048%	11.048%	11.048%
53 OPUC Fee Rate	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%	0.313%
Utility Income Taxes								
54 Book Revenues	46,663	919	47,582	(312)	47,269	(3,320)	(3,595)	40,354
55 Book Expenses	24,653	(638)	24,015	(10)	23,990	(3,447)	(3,580)	16,963
56 Interest Deduction	13,749	275	14,024	(0)	13,737	31	(4)	13,764
57 Production Deduction	-	-	-	-	-	-	-	-
58 Permanent Ms	-	(627)	(627)	-	(627)	-	-	(627)
59 Deferred Ms	-	68,402	68,402	-	68,402	3,338	-	71,740
60 Taxable Income	8,260	(66,493)	(58,232)	(302)	(58,232)	(3,242)	(11)	(61,485)
61 Current State Tax	629	(5,063)	(4,434)	(23)	(4,434)	(247)	(1)	(4,681)
62 State Tax Credits	-	-	-	-	-	-	-	-
63 Net State Taxes	629	(5,063)	(4,434)	(23)	(4,434)	(247)	(1)	(4,681)
64 Federal Taxable Income	7,631	(61,430)	(53,799)	(279)	(53,799)	(2,995)	(10)	(56,804)
65 Current Federal Tax	2,671	(21,501)	(18,829)	(98)	(18,830)	(1,048)	(4)	(19,881)
66 Federal Tax Credits	(19,782)	25	(19,757)	-	(19,757)	-	-	(19,757)
67 ITC Amort	-	-	-	-	-	-	-	-
68 Deferred Taxes	-	27,326	27,326	-	27,326	1,333	-	28,659
69 Total Income Tax Expense	(16,482)	788	(15,694)	(121)	(15,694)	38	(4)	(15,660)
70 Regulated Net Income								
71 Check Regulated NI								

UE 283 / PGE / 1800
Pope - Lobdell

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PW2 / Tucannon

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Maria Pope
James Lobdell

July 16, 2014

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Maria Pope. My position at PGE is Senior Vice President of Power Supply and Operations and Resource Strategy. My qualifications appear in PGE Exhibit 400.

My name is Jim Lobdell. I am Senior Vice President, CFO and Treasurer. My qualifications appear in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to reply to the testimonies of the Public Utility Commission of Oregon (OPUC) Staff, the Industrial Customers of Northwest Utilities (ICNU), and the Citizens' Utility Board of Oregon (CUB) on the Port Westward 2 (PW2) and Tucannon River Wind Farm (Tucannon) generation resources.

Q. What specific issues will you address?

A. We address three issues:

- OPUC Staff (Staff) finds PGE's proposed tariff rider reasonable. However, Staff continues to review data responses from PGE on project costs for PW2 and Tucannon and has provided no indication of concern regarding the prudency of the new generation resources.
- CUB proposes to disallow a portion of PW2 rate base, "that represents the difference between the more expensive flexible resource PGE claimed to need, and the less flexible peaking resource that PGE is actually operating."[1] CUB claims that when PW2 comes online it will be significantly different than what was proposed in PGE's Request for Proposals (RFP).

[1] UE 283 CUB/100/Jenks-McGovern/7

- ICNU states that it believes the development of PW2 has been justified exclusively on the basis that it would be used for full self-integration[2] of Biglow Canyon Wind Farm (Biglow) and Tucannon. ICNU proposes to disallow all costs and benefits associated with PW2 because ICNU claims PGE will not use PW2 for full self-integration of Biglow and Tucannon when it comes online.

Q. Did parties raise any issues on Tucannon?

A. No issues were raised regarding Tucannon and therefore PGE is not providing any testimony on the matter with the exception of an update on the project's status and revenue requirement.

Q. How is the remainder of your testimony organized?

A. The remainder of our testimony is organized as follows:

- Section II: Parties' Proposed Adjustments
- Section III: Port Westward 2 Project Costs
- Section IV: Tucannon River Wind Farm Project Costs
- Section V: Conclusion

[2] Full self-integration is defined as PGE being solely responsible for handling all aspects (regulation, following, imbalance, forecast error, etc.) of its wind resources.

II. Parties' Proposed Adjustments

A. Staff Issues

Q. Has Staff stated a position regarding the prudency to invest in PW2 and Tucannon?

A. No. Staff has not specified a position on the prudency of PGE's decision to invest in PW2 and Tucannon. They state that they are "...still investigating the prudence of pursuing the PW2 and Tucannon River projects,"[3] for the following reasons:

- Staff has not completed reviewing PGE's responses to data requests regarding the actual and anticipated costs of the projects, operating costs, and net variable power costs.
- Staff cannot determine the reasonableness of project costs yet to be incurred.

Q. Didn't the Commission already decide on PGE's decision to pursue PW2 and Tucannon?

A. Yes. The decision and prudency to pursue PW2 and Tucannon was acknowledged and determined through PGE's 2009 IRP (Docket No. LC 48), PGE's 2012 Capacity and Energy Power Supply Resources RFP (Docket No. UM 1535) and PGE's 2012 Renewable Resource RFP (Docket No. UM 1613). In Order No. 10-457, the Commission acknowledged PGE's 2009 IRP action plan which identified the need for approximately 200 MWs of flexible capacity and 122 MWa of renewable energy to meet the 2015 Renewable Portfolio Standard (RPS) target.[4]

PGE's 2012 Capacity and Energy Power Supply Resources RFP, which both the independent evaluator and Staff concluded was conducted in a fair and transparent manner

[3] UE 283 Staff/900/Ordonez/2
[4] PGE's 2009 Update adjusted the need for renewable energy from 122 MWa to 101 MWa.

consistent with the OPUC's Competitive Bidding Guidelines,[5] resulted in the selection of the PW2 project as the least-cost, least-risk bid. Similarly, PGE's 2012 Renewable Resource RFP, which both the independent evaluator and Staff concluded met the Commission's RFP approval criteria and was conducted in a fair and unbiased manner,[6] resulted in the selection of the Tucannon project as the least-cost, least-risk bid.

Q. Does Staff have the information needed to determine the reasonableness of PW2 and Tucannon's project costs?

A. Yes. PGE has provided information in response to over two dozen data requests related to PW2 and Tucannon. These responses covered requests from parties on several areas, including:

- RFP Bid Documentation
- Projected and Actual Costs to Date
- Wind and Load Integration
- Revenue Requirement Update – provided on May 12, 2014 in PGE's First Supplemental Responses to OPUC Data Request Nos. 437 and 443, included as PGE Exhibits 1801 and 1802.

In addition to responding to numerous data requests, PGE met with Staff to review the PW2 and Tucannon RFP bid documents as well as the projects' as-filed costs to ensure PGE is transparent and providing sufficiently detailed information on the prudency of the projects' costs.

[5] Commission Order No. 13-345 (UM 1535)
[6] Commission Order No. 12-376 (UM 1613)

Q. In response to OPUC Staff data requests, PGE has provided actual costs to date, project budgets and updates to the projects' revenue requirement. Is PGE providing an update in this testimony?

A. Yes. Similar to the plant-related revenue requirement updates provided on May 12, 2014,[7] in Section III and IV below, PGE provides an update on expenditures to date and projected costs for PW2 and Tucannon, which are on scope, on budget, and on schedule.

Q. Referring to Staff Exhibit 902, does PGE have any issues with Staff's proposed tariff rider conditions?

A. No. Similar to PacifiCorp's approved tariff rider for the Mona to Oquirrh transmission line,[8] if PGE's tariff rider is approved by the Commission, PGE will work with the parties' to audit and review the final costs for both projects. PGE believes it has been transparent and has provided up-to-date details on project costs and will continue to do so. Should parties prefer, PGE can provide periodic updates on the projects' status and costs.

B. CUB Issues

Q. What is CUB's position regarding PW2?

A. CUB's position is that PW2 will be significantly different than what was proposed in the RFP and therefore it is imprudent for PGE to recover all project costs.

Q. What resources did PGE propose to acquire in its 2012 Capacity and Energy Power Supply Resources RFP?

A. PGE's RFP sought various capacity resources, including approximately 200 MW of flexible capacity:

[7] See PGE Exhibits 1801 and 1802 (actuals as of April 2014).
[8] See Docket No. UE 246, Order No. 12-493 at 7.

> "PGE is seeking to acquire new resources that will fill the dual function of providing capacity to *maintain supply reliability during peak demand periods and other contingencies, while also providing needed flexibility to address variable load requirements* <u>*and*</u> *increasing levels of intermittent energy resources.*"[emphasis added][9]

PGE's RFP was approved by the Commission on June 7, 2012. As stated in the excerpt above, PGE sought a resource capable of providing capacity for peak demand, the integration of variable energy resources, <u>and</u> variability of load.

Q. Why does CUB claim that PW2 is different than what was proposed in the RFP?

A. CUB claims PW2 is different for two reasons:

- First, CUB relies on ICNU's statement that the, "RFP assumed Port Westward 2 would dispatch in 74 percent of hours in 2015," whereas, "MONET only models Port Westward 2 to dispatch in 13 percent of the hours of the year,"[10] and
- Second, when PW2 comes online, PGE will not be fully integrating variable energy resources.

Q. Why is PW2 expected to dispatch significantly less than the 74 percent that ICNU believes the RFP has assumed for PW2?

A. As provided in PGE's response to ICNU Data Request No. 079, Confidential Attachment A in the UE 286 proceeding (provided as PGE Exhibit 1803), all flexible capacity resources in the RFP were dispatched for the dual purposes of meeting the required "forced dispatch" profile <u>and</u> economic dispatch. The economic dispatch logic compares the variable dispatch costs (gas, variable O&M) of the RFP bid to the market curve of energy. The "forced dispatch" profile is an <u>illustrative</u> forecast developed solely for the purpose of scoring RFP

[9] PGE's 2012 Capacity and Energy Power Supply Resources RFP (dated January 25, 2012) at 1.
[10] UE 286 ICNU/100/Mullins/9 line 8-10.

bids and is not a firm commitment from PGE.[11] In order to fairly and equally assess each flexible capacity bid on the same variable cost basis for energy and flexibility, PGE evaluated all bids using a "forced dispatch" profile to gauge flexibility for providing ancillary services.

Second, the "74 percent" ICNU references in PGE's Capacity and Energy Power Supply Resources RFP was not based on PW2 but was a bid requirement used for the sole purpose of scoring and evaluating RFP bids.

Q. Was the PW2 "forced dispatch" profile used in the RFP evaluation included in MONET when determining PW2's dispatch?

A. No. As stated above, the forced dispatch profile is an <u>illustrative</u> forecast developed solely for the purpose of scoring RFP bids and was not a commitment from PGE. As described in PGE's response to OPUC Data Request No. 027 in the UE 286 proceeding (provided as PGE Exhibit 1804), PGE resources (including PW2) cannot fully self-integrate wind prior to October 1, 2015.

> "Port Westward 2 is capable of providing both peaking and flexible capacity…Although Port Westward 2 is a highly flexible resource, it is not PGE's singular balancing resource, but rather an important resource in PGE's generation fleet capable of providing flexible capacity."

Even though PW2's dispatch in MONET differs from the dispatch in the RFP evaluation, PGE did include an outboard adjustment for the estimated benefits of full self-integration related to PW2 for the fourth quarter of 2015 in our net variable power costs forecast.

Q. Why is Q4 of 2015 the earliest that PGE could pursue full self-integration or some other hybrid approach?

[11] UM 1535 – PGE's Capacity and Energy Power Supply Resources RFP at 80.

A. As stated in PGE's response to OPUC Data Request No. 511 (provided as PGE Exhibit 1805),

> "PGE's strategy to self-integrate wind is not focused exclusively on utilizing Port Westward 2. Instead, integration of wind resources is conducted on a portfolio basis...PGE is taking a systematic and methodical approach in its strategy for wind integration, including potential self-integration. PGE's next opportunity to evaluate self-integration is the BPA April 2015 election for the period of October 2015 to October 2017."

PW2 was selected as the highest scoring flexible capacity resource bid in the RFP on January 31, 2013. In April 2014, PGE had to elect whether to continue with BPA Variable Energy Resource Balancing Service (VERBS) for the period October 1, 2014 through September 30, 2015. PGE elected to continue with BPA VERBS 30/60 committed scheduling for service beginning on October 1, 2014. Currently, PW2 is on scope, on budget, and on schedule to be online in January 2015. If PGE elected full self-integration of Biglow and Tucannon for the April 2014 BPA mid-rate-period election, this would mean that PGE would have to self-integrate all aspects of wind beginning October 1, 2014, prior to PW2 being commercially available and prior to having the necessary systems in place to do so. As also stated in PGE Exhibit 1805,

> "In order to elect self-integration (or some combination thereof) PGE must install Automatic Generation Control (AGC) on additional generation assets and deploy improved data and communication systems as well as dynamic load and dispatch tools. PGE is addressing this work under the Dynamic Dispatch Program (DDP), and it is a key component of PGE's methodical approach in its strategy for wind integration."

For further details on BPA VERBS please see PGE Exhibit 200 in the UE 286 proceeding, which discusses wind integration; for convenience, provided as PGE Exhibit 1806.

Q. Please summarize the Dynamic Dispatch Program (DDP).

A. As further described in PGE Exhibits 1805 and 1806, the DDP is a complex undertaking and requires a long period for development, implementation, and testing of the necessary systems, software, and equipment. The program has been organized into the following three integration-related efforts:

- PI Consolidation – consolidate current generating plant PI systems and expand a centralized PI system to include data from all generating plants.
- Cycling Cost Studies & Automated Generation Control (AGC) Telemetry Installation – PGE is conducting studies on PGE's thermal resources to determine their cycling capabilities and the costs associated with using them for integration (wear and tear, forced outage rates, etc.). Based on the outcome of the cycling cost studies, PGE will install AGC at the appropriate thermal plants.[12]
- Dynamic Dispatch Tool – this project will create/purchase a tool(s) that can simultaneously optimize the PGE system for reliability requirements and economic dispatch of the plants. This will support PGE's ability to 1) self-integrate wind, 2) participate in an Energy Imbalance Market (EIM), and 3) automatically dispatch plants more efficiently to load.

PGE expects to complete the DDP by October 1, 2015. Collectively, this work will help inform PGE's strategy for wind integration, including potential full self-integration beginning in October 2015.

[12] AGC is an important and necessary system, but not sufficient on its own for PGE to fully self-integrate wind.

Q. CUB proposes a disallowance, "that represents the difference between the more expensive flexible resource PGE claimed to need, and the less flexible peaking resource that PGE is actually operating."[13] Is CUB's proposed disallowance reasonable?

A. No. The proxy resource CUB references in its testimony is an unmodified frame simple cycle combustion turbine. As CUB points out, in PGE's Reply Comments during the UM 1535 RFP proceeding, PGE stated:

> "Unmodified frame simple cycle combustion turbines such as that described in footnote 8 of NIPPC's comments are only being commercially used as peaking units. While such units may meet PGE's seasonal peaking needs, there is no certainty that they can provide intra-hour ancillary service needed for load following and integration of variable energy resources."[14]

An unmodified frame simple cycle combustion turbine would not be capable of meeting PGE's flexible capacity needs for the integration of variable resources <u>nor</u> the variability of load due to:

- Operating limits – units cannot turn down past 50% of their nameplate capacity.
- Technological limits – PGE is aware of only five units of unmodified frame technology that are currently used, which are used for peaking generation.
- Increased variable costs – very expensive operating and maintenance costs and poor heat rate performance.

When PW2 comes online it will provide capacity for peak demand and intra-hour ancillary services needed for integrating variations in load (i.e., load following). Under CUB's proposal, they would remove costs and benefits associated with load following, which PW2 will provide when it comes online.

[13] UE 283 CUB/100/Jenks-McGovern/7
[14] UM 1535 – PGE's Reply Comments (dated July 8, 2011) at 2

As stated above, PW2 has the capability to provide flexible capacity for wind integration; however, PW2 is not the singular balancing resource, but rather one important resource in PGE's generation fleet capable of providing flexible capacity. PGE is taking a systematic and methodical approach in its strategy for wind integration, including potential full self-integration. PGE's next opportunity to evaluate full self-integration is the BPA April 2015 election for the period of October 2015 to October 2017. PGE is continuing to work toward a decision point in April 2015 to integrate variable energy resources (VERs) in the least-cost, least-risk manner for its customers.

Q. Have other parties found PGE's approach to integrating wind reasonable?

A. Yes. In OPUC Staff's reply testimony in the UE 286 proceeding, OPUC Staff found,

> "PGE reasonably entered into the BPA contract for twelve months of integration services, notwithstanding that PW2 was scheduled to come on line during that period...Staff believes that PGE's decision to enter into a contract with BPA to integrate its wind resources for the first three quarters of the test year was reasonable."[15]

C. ICNU Issues

Q. Please summarize ICNU's proposal regarding PW2?

A. ICNU proposes that the costs and benefits associated with PW2 be excluded from rates until it can be used to fully self-integrate both Biglow and Tucannon.

Q. Has ICNU proposed other adjustments related to PW2 providing self-integration? If so, what is ICNU's other proposal?

A. Yes. ICNU's proposal mentioned above is an alternative to one of their proposals made in PGE's 2015 Annual Update Tariff proceeding (UE 286). In the UE 286 proceeding, ICNU

[15] UE 286/Staff/200/Crider-Ordonez/9

proposes that PGE model its 2015 NVPC to reflect ICNU's estimated net benefit of full self-integration of Biglow and Tucannon for the entire 2015 test year.

Q. What is ICNU's overall position on PW2 integrating wind?

A. ICNU believes that the development of PW2 has been justified solely on the basis that the plant would be used to fully self-integrate PGE-owned wind resources. If PGE is incapable of fully self-integrating its owned wind resources by the time PW2 is placed in service or if PGE does not include a full year of estimated full self-integration benefits in net variable power costs, ICNU recommends the PW2 facility, and its associated costs and benefits be disallowed.

Q. Has PGE discussed full self-integration of wind in other testimony?

A. Yes. As mentioned above, PGE Exhibit 1806 provides PGE's reply testimony from the UE 286 proceeding, which details PGE's decision to use BPA VERBS and the steps being taken for PGE to move toward self-integration.

Q. Have other parties provided reply testimony on ICNU's proposal in the UE 286 proceeding?

A. Yes. In the UE 286 proceeding, OPUC Staff provided their analysis on ICNU's proposed adjustments. OPUC Staff found that ICNU had not presented evidence to show that PGE's election to continue to use BPA VERBS through October 2015 was not cost-effective and an imprudent action by PGE. In addition, Staff stated,

> "It is not clear why the Commission should base an adjustment to PGE's NVPC on the assumption PGE could self-integrate all its resources for the entire test year and three months of the preceding year when the record does not establish this assumption is accurate."[16]

[16] UE 286/Staff/200/Crider-Ordonez/8

OPUC Staff did not agree with ICNU's recommendation to require PGE to calculate net variable power costs as if it elected full self-integration of Biglow and Tucannon for the entire 2015 test year.

Q. Please summarize PGE's decision to use BPA VERBS and the steps being taken to inform PGE's decision regarding wind integration in April 2015.

A. Currently, PW2 is on scope, on budget, and on schedule to be online in January 2015. If PGE elected full self-integration of Biglow and Tucannon for the April 2014 BPA mid-rate-period election, this would mean that PGE would have to self-integrate all aspects of wind beginning October 1, 2014, prior to PW2 being commercially available and prior to having the necessary systems in place to do so, which could place more costs and risks on customers. In addition, as mentioned above, Staff found that PGE's decision to enter into a contract with BPA to integrate its wind resources for the first three quarters of the test year was reasonable.

PGE's next decision regarding wind integration services is informed by multiple issues, many of them external to PGE such as the evolving BPA rates/products, regional issues and market solutions. Internally, PGE has developed multiple Wind Integration Study phases and participated in BPA's 30/30 Committed Intra Hour (CIH) pilot program to better understand wind and integration costs, and systems necessary for full self-integration.

PGE is taking a methodical approach to a complex issue and working towards a decision in April 2015 to integrate VERs in the least-cost, least-risk manner for its customers. PGE's strategy to integrate wind is not focused exclusively on using Port Westward 2. Instead, integration of wind resources is conducted on a portfolio basis. As stated above, in order to elect full self-integration (or some hybrid approach) PGE must install AGC on all additional generation assets and deploy improved data and communication systems as well as dynamic load and dispatch tools, all of which PGE is addressing under the DDP.[17] For further details please see PGE Exhibit 1806.

Q. Is ICNU's proposed disallowance reasonable?

A. No. Forcing a decision to fully self-integrate prematurely, as ICNU seems to want, could place more cost and risk on customers. Further, under ICNU's alternative proposal, they would also remove costs and benefits associated with peak demand reliability and load following, which PW2 will provide when it comes online.

PGE is continuing to work toward a decision point in April 2015 to integrate VERs in the least-cost, least-risk manner for its customers. PW2 will provide peak demand reliability and flexibility to address the variability of load when it is placed in service. In addition, PW2 will provide dispatch benefits to customers when it is placed in service and these benefits are included in PGE's NVPC forecast for 2015.

[17] AGC is an important and necessary system, but not sufficient on its own for PGE to fully self-integrate wind.

III. Port Westward 2 Project Costs

Q. Has PGE updated costs for PW2 since its initial filing?

A. Yes. PGE has answered multiple data requests regarding the costs for PW2. The most recent update was provided in response to OPUC Data Request No. 437, provided as PGE Exhibit 1801.

Q. Did the PW2 revenue requirement change?

A. Yes. It increased slightly from $51.4 million to $53.5 million. In the process of updating the revenue requirement for PW2 and Tucannon, PGE identified a reduction in deferred tax assets related to the base business of approximately $32.7 million,[18] or a revenue requirement reduction of approximately $3.8 million.

Q. Did the capital expenditures change?

A. No. PGE is still expecting capital expenditures to be approximately $300 million. However, PGE updated its filing because there were some costs that were inadvertently left out of the initial filing. These changes are detailed in PGE Exhibit 1801.

Q. What were some of the major drivers that changed the PW2 revenue requirement?

A. There were several components that were updated which are detailed in PGE Exhibit 1801. Briefly, the major drivers were:

- Net Variable Power Costs
- Depreciation Expense
- Average Gross Plant
- Schedule Ms

Q. Did the update, as detailed in PGE Exhibit 1801, include any actual costs?

[18] Settlement was reached on multiple items which includes the $32.7 million in deferred tax assets (not including deferred PTCs).

A. Yes. The update included actual costs through April 2014, which represent approximately 64% of the total project costs.

Q. Is PGE providing an update in this testimony?

A. Yes. The updated costs for PW2 include actual costs through May 2014, which represent approximately 70% of the total project costs.

Q. Please summarize the updated PW2 costs and explain any variance from the May 12 update provided in PGE's response to OPUC Staff Data Request No. 437.

A. Costs for PW2 consist of the following categories:

- Net Variable Power Costs – the dispatch benefits are approximately $1.27 million, $0.8 million less than the May 12 update. This decrease is due to updated market forward curves and day-ahead forecast error in PGE's July Power Cost Update in UE 286.
- Production O&M – forecasted to be approximately $1.5 million. This amount is unchanged from the May 12 update.
- Insurance and A&G – forecasted to be approximately $0.3 million. This amount is unchanged from the May 12 update.
- Property Taxes – forecasted to be approximately $1.7 million. This amount is unchanged from the May 12 update.
- Depreciation expense – forecasted to be approximately $9.5 million, which is $4.8 million less than the May 12 update. This decrease is attributed to the Stipulation in Docket No. UM 1679 (PGE's Depreciation Study) filed on June 30, 2014.

- Average Rate Base – forecasted to be approximately $319.2 million, which is $0.2 million more than the May 12 update. This increase is attributed to the Stipulation in Docket No. UM 1679, filed June 30, 2014.
- Schedule Ms – Deferred Schedule Ms are forecasted to be approximately $6.2 million in the 2015 test year, which is $4.8 million more than the May 12 update. This increase in Deferred Schedule Ms is attributed to the Stipulation in Docket No. UM 1679 filed June 30, 2014. Permanent Schedule Ms are unchanged from the May 12 update.

Table 1 below summarizes the updated PW2 projected costs listed above compared to the May 12 update:

Table 1

PW2 Project Costs ($000)

Project Cost	**May 12 Update***	**July 16 Update****
NVPC	(2,006)	(1,266)
Production O&M	1,479	1,479
Insurance and A&G	347	347
Property Taxes	1,663	1,663
Depreciation Expense	14,337	9,491
Average Rate Base	319,015	319,219
Permanent Schedule Ms	(645)	(645)
Temporary Schedule Ms	1,350	6,196

*Actuals through April 2014
**Actuals through May 2014

Q. What is PW2's updated revenue requirement?

A. The updated revenue requirement is approximately $49.1 million, a decrease of approximately $4.4 million from the May 12 update. Details of this calculation and rate base are included in PGE Exhibit 1701.

IV. Tucannon River Wind Farm Project Costs

Q. Has PGE updated costs for Tucannon since its initial filing?

A. Yes. PGE has answered multiple data requests regarding the costs for Tucannon. The most recent update was provided in PGE's response to OPUC Staff Data Request No. 443, provided as PGE Exhibit 1802.

Q. Did the Tucannon revenue requirement change?

A. Yes. It increased slightly from $46.7 million to $47.6 million. As stated above, in the process of updating the revenue requirement for PW2 and Tucannon, PGE identified a reduction in deferred tax assets related to the base business of approximately $32.7 million,[19] or a revenue requirement reduction of approximately $3.8 million.

Q. Did the capital expenditures change?

A. No. PGE is still expecting capital expenditures to be approximately $500 million. However, PGE updated its filing because there were some costs that were inadvertently left out of the initial filing and PGE wanted to provide the most current actual costs to date. These changes are detailed in PGE Exhibit 1802.

Q. What were some of the major drivers that changed Tucannon's revenue requirement?

A. There were several components that were updated and are detailed in PGE Exhibit 1802. Briefly, the major drivers were net variable power costs benefits, depreciation, and correcting an error in the original filing related to gross plant.

Q. Did the update, as detailed in PGE Exhibit 1802, include any actual costs?

A. Yes. The update includes actual costs through April 2014, which represent approximately 42% of the total project costs.

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[19] Settlement was reached on multiple items which includes the $32.7 million in deferred tax assets (not including deferred PTCs).

Q. Is PGE providing an update in this testimony?

A. Yes. The updated costs for Tucannon include actual costs through May 2014, which represent approximately 56% of the total project costs.

Q. Please summarize the updated Tucannon costs and explain any variance from the May 12 update.

A. Costs for Tucannon consist of the following categories:

- Net Variable Power Costs – the dispatch benefits are approximately $22.4 million, which is $3.4 million more than the May 12 update. This increase is due to PGE's latest July Power Costs Update in UE 286.
- Production O&M – forecasted to be approximately $7.5 million. This amount is unchanged from the May 12 update.
- Insurance and A&G – forecasted to be approximately $0.4 million. This amount is unchanged from the May 12 update.
- Property Taxes – forecasted to be approximately $6.9 million due to PW2. This amount is unchanged from the May 12 update.
- Depreciation expense – forecasted to be approximately $23.2 million, which is $3.3 million less than the May 12 update. This decrease is attributed to the Stipulation in Docket No. UM 1679 filed June 30, 2014.
- Average Rate Base – forecasted to be approximately $505.8 million, which is $1.3 million more than the May 12 update. This increase is attributed to the Stipulation in Docket No. UM 1679 filed June 30, 2014.
- Schedule Ms – Deferred Schedule Ms are forecasted to be approximately $71.7 million in the 2015 test year, which is $3.3 million more than the May 12 update. This increase in

Deferred Schedule Ms is attributed to the Stipulation in Docket No. UM 1679 filed June 30, 2014. Permanent Schedule Ms are unchanged from the May 12 update.

- Production Tax Credits (PTCs) – forecasted to be approximately ($19.8) million in the 2015 test year. This amount is unchanged from the May 12 update.

Table 2 below summarizes the updated Tucannon projected costs listed above compared to the May 12 update:

Table 2

Tucannon Project Costs ($000)

Project Cost	May 12 Update*	July 16 Update**
NVPC	(18,965)	(22,372)
Production O&M	7,470	7,470
Insurance and A&G	435	435
Property Taxes	6,943	6,943
Depreciation Expense	26,547	23,209
Average Rate Base	504,742	505,713
Permanent Schedule Ms	(627)	(627)
Temporary Schedule Ms	68,402	71,740
PTCs	(19,757)	(19,757)

*Actuals through April 2014
**Actuals through May 2014

Q. What is Tucannon's updated revenue requirement?

A. The updated revenue requirement is $40.4 million, which is approximately $6.9 million less than the May 12 update. Details of this calculation and rate base are included in PGE Exhibit 1701.

V. Conclusion

Q. Please summarize PGE's position on the reasonableness of CUB's and ICNU's proposed disallowances.

A. PGE finds neither CUB's nor ICNU's proposed disallowances reasonable. PGE should not be penalized for taking a methodical approach to the complex issue of integrating wind. When it comes to fully self-integrating wind, PGE's strategy is not focused exclusively on utilizing PW2. Instead, integration of wind resources is conducted on a portfolio basis. Furthermore, in order to elect fully self-integration PGE must install AGC on all additional generation assets and deploy improved data and communication systems as well as dynamic load and dispatch tools. If PGE had elected full self-integration of Biglow and Tucannon during the April 2014 BPA mid-rate-period election, this would mean that PGE would self-integrate all aspects of wind beginning October 1, 2014, prior to PW2 being commercially available and prior to having the systems in place. Forcing a decision to self-integrate prematurely, as ICNU seems to want, could place more costs and risks on customers. PGE should not be penalized for the timing of the election window and the online date of PW2 not being aligned.

PGE's next opportunity to evaluate self-integration is the BPA April 2015 election for the period of October 2015 to October 2017. PGE is continuing to work toward a decision point in April 2015 to potentially self-integrate VERs in the least-cost, least risk manner for its customers.

Not only would CUB's proposed adjustment remove costs and benefits associated with wind integration, they would also remove costs and benefits associated with load following, which PW2 will provide when it comes online. As mentioned above, the intra-hour ancillary services needed for load following are the same services needed for integrating variable energy resources. Similarly, under ICNU's proposed adjustment, all costs and benefits associated with PW2 would be removed while PW2 would be providing the benefits of providing capacity to maintain supply reliability during peak demand periods and also providing needed flexibility to address variable load requirements.

As PGE has stated in a multitude of data responses, workshops and testimonies, pursuant to PGE's 2009 IRP (acknowledged per Commission Order No. 10-457), PGE sought a resource capable of providing capacity for peak demand, the integration of variable energy resources, <u>and</u> load following. PGE's 2012 Capacity and Energy Power Supply Resources RFP (UM 1535), which the independent evaluator and Staff concluded was conducted in a fair and transparent manner consistent with the OPUC's Competitive Bidding Guidelines, resulted in the selection of the PW2 project as the least-cost, least-risk bid. PW2 is currently on scope, on budget, on schedule, and will begin providing value to customers in January 2015.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
1801	PGE Response to OPUC Data Request No. 437
1802	PGE Response to OPUC Data Request No. 443
1803C	PGE Response to UE 286 ICNU Data Request No. 079 Attachment A
1804	PGE Response to UE 286 OPUC Data Request No. 027
1805	PGE Response to OPUC Data Request No. 511
1806	UE 286 PGE Exhibit 200 (Wind Integration excerpt)

May 12, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE First Supplemental Response to OPUC Data Request No. 437
Dated April 17, 2014

Request:

Regarding PGE response to Staff Data Request 243 part "h," where the Company provided the Attachment D to justify the approximately $310 million of "Avg. Gross Plant,"[1] please:

a. **Provide the capital cost value input (Capital Cost Value Input) from which the $310 million of "Avg. Gross Plant" was derived. By Capital Cost Value Input, Staff refers to the capital costs that are comparable to cell "I20" in workbook "PW2_Recip_Capital_budget," worksheet "Capital Budget" of the Confidential Attachment 248-B of PGE response to Staff Data Request 248 "e," where the Company provided the EPC capital costs of the winning bid from the RFP in Docket No. UM1535.**
b. **Provide a detailed explanation of the differences *between* the Capital Cost Value Input from which the $310 million of "Avg. Gross Plant" was derived *and* the cell "I20" in workbook "PW2_Recip_Capital_budget," worksheet "Capital Budget" of the Confidential Attachment 248-B of PGE response to Staff Data Request "e".**

Response (April 30, 2014):

a. The $310 million rate base amount is based on an average of averages of Port Westward 2 (PW2) gross plant. This calculation can be seen in PGE's Response to

[1] See PGE's workpaper workbook file "Exhibit Support," worksheet "Rev Req pw2," cell "F38"

OPUC Data Request No. 243, Attachment 243-D, cell O117. Additionally, the gross plant amounts used for calculating average rate base include Allowance for Funds Used During Construction (AFUDC). For comparison to the bid amount, which is at a point in time and excludes AFUDC and capitalized property taxes, the capital amounts provided below are not averages and exclude AFUDC and capitalized property taxes. The table below, provides the "overnight" capital cost estimates for PW2 from the RFP bid and PGE's budget:

Port Westward 2	RFP Bid*	GRC Budget	Variance
"Overnight" Capital	$ 298,819,100	$ 289,898,026	
Capital Budget Correction		$ 7,851,561	
"Overnight" Capital Budget	$ 298,819,100	$ 297,749,587	$ (1,069,513)

** The RFP bid capital amount referred to in cell "I20" in the "Capital Budget" tab of workbook PW2_Recip_Capital_budget.xlsx (Confidential Attachment 248-B) does not include the additional $10 million cost for currency exchange (euros to dollars). This is noted in the footnote of the 'Capital Budget' worksheet, which shows the total of $298,819,100.*

b. PGE updates its forecast for PW2 on a monthly basis. This forecast includes two components; actuals to date and the remaining forecast. During the preparation of PGE's PW2 capital budget amount for the general rate case (GRC), PGE reflected the current version for actuals to date, but inadvertently included an older estimate of the remaining forecast amount. This resulted in capital costs being understated by approximately $7.9 million.

   Based on the revised GRC budget of $297,749,587, PGE's budget is approximately $1.1 million under the RFP bid's capital budget. This variance is primarily due to two factors:

   - Actual development costs were less than the estimated amount included in the owner's costs for the RFP. More specifically, these are the preliminary engineering costs that were incurred prior to the project being selected as the winning bid.
   - When the Engineering, Procurement, Construction (EPC) contract was finalized and executed the actual cost for Builder's All Risk Insurance was less than the bid's estimated cost.

First Supplement Response (May 12, 2014):

Per a conversation with the OPUC Staff on April 14, 2014, PGE provides the following revenue requirement update for PW2.

Port Westward 2 Annualized Revenue Requirement	Total ($000)
Original Filing	$ 51,371
May Update	$ 53,476
Variance	$ 2,105

The revenue requirement variance is driven primarily by the three following areas:

- Net Variable Power Costs – the dispatch benefits increased primarily due to the addition of self-integration benefits from PW2 in Q4 of 2015.
- Depreciation expense – The increase in depreciation expense is primarily attributed to updated capital allocations. PGE originally allocated the PW2 estimated Plant in Service capital costs by 300-level FERC accounts similar to Port Westward 1. After further review, PGE has updated and improved its capital allocations for PW2. The reallocation has moved a portion of capital costs into FERC Accounts 356 (Transmission Overhead Conductor) and 397 (General Plant Communication Equipment). These two accounts have shorter depreciable lives or higher salvage cost rates, resulting in increased depreciation expense.
- Property Taxes – For further details, please see PGE's Response to ICNU Data Request No. 118.
- Average Gross Plant – The increase in average gross plant is attributed to the revised PW2 capital budget as discussed in part b above.
- Average Accumulated Deferred Taxes (ADIT) – The increase in ADIT asset is due to 1) the revised PW2 capital budget and related book depreciation increase, and 2) a reduction to the utilization of production tax credits.
- Permanent Schedule Ms – PGE inadvertently did not include Schedule Ms in the initial filing for PW2. Schedule Ms are included in the revised PW2 revenue requirement.

Attachment 437-A_Supp 1 provides the work paper support for the updated PW2 annualized revenue requirement.

In the process of updating the revenue requirement for Tucannon and PW2, PGE identified a reduction in deferred tax assets related to the base business of approximately $32.7 million, or a revenue requirement reduction of approximately $3.8 million.

UE 283

Attachment 437-A_Supp 1

Provided in Electronic Format Only

PW2 Updated Rev Req Work Paper

Exhibit 1801

Attachments to PGE Response to OPUC Data Request No. 437

Provided Electronically Only

May 12, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 443
Dated April 17, 2014

Request:

Regarding PGE response to Staff Data Request 251 part "g," where the Company provided the Attachment B to justify the approximately $510 million of "Avg. Gross Plant," please:

a. **Provide the capital cost value input (Capital Cost Value Input) from which the $510 million of "Avg. Gross Plant" was derived. By Capital Cost Value Input, Staff refers to the capital costs that are comparable to cell "C26" in workbook file "109-3_ProForma_Projections_CONF," worksheet file "Assumptions & Projections" of the PGE response to Staff Data Request 253 part "e,"[1] where the Company provided the capital costs of the winning bid that resulted from the RFP in Docket No. UM1623.**
b. **Explain any differences *between* Capital Cost Value Input from which the $510 million of "Avg. Gross Plant" was derived *and* the cell "C26" in workbook file "109-3_ProForma_Projections_CONF," worksheet file "Assumptions & Projections" of the PGE response to Staff Data Request 253 part "e."**

[1] To respond to Staff Data Request 253 part "e," PGE referred to PGE response to CUB Data Request No. 15 in Docket No. UE283. Specifically Attachment 015-B.

Response (dated May 1, 2014):

a. The $510 million average gross plant amount is based on an average of averages of Tucannon River Wind Farm (Tucannon) gross plant. This calculation can be seen in PGE's Response to OPUC Data Request No. 251, Attachment 251-B, cell O117. Additionally, the gross plant amounts used for calculating average rate base include Allowance for Funds Used During Construction (AFUDC).

For comparison to the bid amount, which is at a point in time and excludes AFUDC and capitalized property taxes, the capital amounts provided below are not averages and exclude AFUDC and capitalized property taxes. The table below, provides the "overnight" capital cost estimates for Tucannon from the RFP bid and PGE's budget:

Tucannon River Wind Farm	RFP Bid*	GRC Budget
"Overnight" Capital	$ 523.0	$ 487.4
Capital Budget Correction		5.2
Contingency reserve adjustment		5.9
Land owner's fee		1.5
Washington Sales Tax Exemption		23.0
"Overnight" Capital Budget	$ 523.0	$ 523.0

**The bid amount from RES was $523 million and did not include a sales tax refund of $23 million, therefore the net bid amount is $500 million.*

b. PGE updates its forecast for Tucannon on a monthly basis. This forecast includes two components; actuals to date and the remaining forecast. During the preparation of PGE's Tucannon capital budget amount for the general rate case (GRC), PGE reflected the current version for actuals to date, but inadvertently included an older version for the remaining forecast amount. This resulted in capital costs being understated by approximately $5.2 million.

As PGE has explained in PGE/400, page 15, beginning at line 14, PGE was able to participate in Washington's Renewables Sales Tax Exemption. PGE will realize sales tax savings of $23 million compared to the bid amount. PGE's revised GRC budget is approximately $500.0 million, which includes the approximate $23 million tax credit.

First Supplement Response (dated May 12, 2014):

As stated in PGE's Response to OPUC Data Request No. 441, PGE is providing the following revenue requirement update for Tucannon.

Tucannon River Wind Farm Annualized Revenue Requirement	Total ($000)

Original Filing	$ 46,663
May Update	$ 47,582
Variance	$919

The revenue requirement variance is driven primarily by the following:

- Net dispatch benefits have increased by $2.5 million due to the estimated earlier on-line date of Tucannon.
- O&M expense has decreased by approximately $1 million as described in PGE's Response to OPUC Data Request No. 441.
- Depreciation expense has increased by approximately $2.9 million primarily due to a reallocation of 300-level accounts. This update allocates the payment to Puget Sound Energy for transmission credit rights from BPA to FERC Account 302, Franchises and Consents. This account has a shorter depreciable life (5 years), resulting in increased depreciation expense.
- Average gross plant has increased by approximately $12.6 million as discussed above in PGE's Response to OPUC Data Request No. 437 dated May 1, 2014.
- Accumulated Deferred Taxes increased by approximately $3 million, which is due to, 1) the revised Tucannon capital budget and related book depreciation increase, and 2) Tucannon's estimated in-service date moving from 2015 to 2014.
- Permanent schedule Ms were inadvertently excluded from the PGE's UE 283 filing in February. Permanent schedule Ms are included in the revised Tucannon revenue requirement.

Attachment 443-A_Supp 1 provides the work paper support for the updated Tucannon revenue requirement.

In the process of updating the revenue requirement for Tucannon and Port Westward 2, PGE identified a reduction in deferred tax assets related to the base business of approximately $32.7 million, or a revenue requirement reduction of approximately $3.8 million.

UE 283

Attachment 443-A_Supp 1

Provided in Electronic Format Only

Tucannon River Wind Farm
Updated Revenue Requirement Work Paper

Exhibit 1802

Attachments to PGE Response to OPUC Data Request No. 447

Provided Electronically Only

Exhibit 1803C

Confidential

June 25, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 286
PGE Response to OPUC Data Request No. 027
Dated June 18, 2014

<u>Request:</u>

Regarding PGE's response to Staff Data Request 510, part "e" of Docket No. UE 283, where the Company represented:

> *"PGE's strategy to self-integrate wind is not focused exclusively on utilizing Port Westward 2. The integration of wind resources is conducted on a portfolio basis."*

Please respond the following questions:

a. **As of the time of the PGE's 2009 IRP (or 2009 IRP Update), please provide, for each year of the IRP analysis (e.g., 20 years), the allocation of Port Westward 2 Power Plant's capacity for each type of capacity (i.e, "peak capacity" and "flexible capacity") as described in Action Item 11 of PGE'S 2009 IRP;**[1]
b. **From the response to part "a" of this question related to PGE's 2009 IRP (or 2009 IRP Update), was the capacity of Port Westward 2 enough to integrate all [note emphasis] the wind resources PGE anticipated (i.e., Biglow Canyon Wind Farm and Tucannon River Wind Farm)? Please provide a comprehensive explanation;**

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[1] In PGE's 2009 IRP, PGE represented: "PGE requests acknowledgement of up to 200 MW of flexible capacity resources by year-end 2013 to fill a dual function of providing capacity to maintain supply reliability during peak demand periods [peak capacity] and providing needed flexibility [flexible capacity] to address variable load requirements and increasing levels of intermittent energy resources." See page 325, Action Item 11 of PGE's 2009 IRP at http://edocs.puc.state.or.us/efdocs/HAA/lc48haa151359.pdf

c. **As of the time of PGE's 2012 RFP (January 31, 2013; when the Addendum to the Final Report of the Independent Evaluator was issued),[2] please provide, for each year of the RFP analysis (e.g., 20 years), the allocation of Port Westward 2 Power Plant's capacity for each type of capacity (i.e., "peak capacity" and "flexible capacity");**
d. **From the response to part "c" of this question related to PGE's 2012 RFP, was the capacity of Port Westward 2 enough to integrate all [note emphasis] the wind resources PGE anticipated (i.e., Biglow Canyon Wind Farm and Tucannon River Wind Farm)? Please provide a comprehensive explanation;**
e. **As of the date of responding this data request, please provide for the Port Westward 2 Power Plant, the allocation of its capacity for each type of capacity ("peak capacity" and "flexible capacity"), annually, for the next five years; and**
f. **From the response to part "e" of this question, is the capacity of Port Westward 2 enough to integrate all [note emphasis] the wind resources PGE anticipates (i.e., Biglow Canyon Wind Farm and Tucannon River Wind Farm)? Please provide a comprehensive explanation.**

In responding the above sub-question please fills the following table for each year requested:

Year: 2015 (example)

Uses of the Port Westward 2 Power Plant	MW	%
Peak capacity		
Flexible capacity for integrating load		
Flexible capacity for integrating intermittent wind resources.		
Flexible capacity for integrating intermittent non-wind resources.		
Total		

Response:

PGE objects to this request to the extent that it calls for speculation and is based on inaccurate assumptions and/or an incomplete premise. Notwithstanding this objection, PGE responds as follows:

[2] In the 2012 RFP related to the Port Westward 2 Power Plant, the Independent Evaluator represented that "After incorporating updated assumptions for load and resources, PGE continues to show significant deficits for energy and capacity prior to acknowledged Action Plan fulfillment. These deficits are only modestly lower than those outlined in our filed 2009 IRP. We plan to fill most of this need through the aforementioned Combined Capacity/Baseload Energy and Renewables RFPs..." See page 21; "Resource Requirement and Input Updates" at http://edocs.puc.state.or.us/efdocs/HAD/lc48had152312.pdf

For the purposes of resource planning, PGE does not apportion by use the capacity of its resources capable of filling dual capacity functions. Rather, PGE evaluates a resource's ability to provide capacity by the metric it is assessing. For example:

1) Peak Capacity: With respect to assessing a resource's ability to provide capacity to maintain supply reliably during peak demand periods and to provide service during transmission or other generation disruptions (i.e., peaking capacity), PGE identifies the amount of firm hourly power a resource is capable of providing when called for in a given hour.

2) Flexible Capacity: With respect to assessing a resource's ability to provide capacity to follow load (i.e., load following) and integrate variable energy resources (e.g., wind following), PGE identifies a resource's ability to rapidly increase or decrease energy production.

Port Westward 2 is capable of providing both peaking and flexible capacity up to its full nameplate capacity. However, as an operational matter, Port Westward 2 cannot meet all capacity purposes simultaneously. The capability of Port Westward 2 to provide flexible capacity will be limited at varying times and by varying degrees by the operational choices PGE makes in order to reliably supply power in a least-cost manner. See PGE's response to OPUC Data Request No. 296 in UE 283 for a list of the operational considerations that can limit Port Westward 2's capability to integrate variable energy resources (VERs).

Although Port Westward 2 is a highly flexible resource, it is not PGE's singular balancing resource, but rather an important resource in PGE's generation fleet capable of providing flexible capacity. In order to elect self-integration (or some combination thereof) PGE must install Automatic Generation Control (AGC) on additional generation assets and deploy improved data and communication systems as well as dynamic load and dispatch tools. PGE is addressing this work under the Dynamic Dispatch Program (DDP), and it is a key component of PGE's methodical approach in its strategy for wind integration. See PGE's response to OPUC Data Request No. 511 in UE 283 for additional explanation of DDP's components.

The DDP is a complex undertaking and it requires a long period for development, implementation, and testing of the necessary systems, software, and equipment. Therefore, PGE expects to complete the DDP by October 1, 2015. While completing the DDP, PGE continues to refine its wind integration studies and monitor developments such as sub-hourly scheduling and energy imbalance markets. Collectively, this work will help inform PGE's strategy for wind integration, including potential self-integration beginning in October 2015.

The sections below identify material specific to questions (a) through (f).

Capacity Provided by Generic Resource - Questions (a) and (c)

At the time of PGE's 2009 Integrated Resource Plan (IRP) and through the issuance of its Energy and Capacity RFP (i.e., prior to the selection of Port Westward 2), PGE identified a need for both traditional peaking capacity and flexible capacity to meet load following net of wind generation needs. In its planning, PGE assigned 200 MW to a generic resource when evaluating its ability to provide peaking capacity. PGE also assigned 200 MW to a generic resource when evaluating its ability to provide flexible capacity.[3]

Capacity Provided by Port Westward 2 - Question (e)

In its 2013 IRP PGE assigned 220 MW to Port Westward 2 when evaluating its ability to provide peaking capacity. PGE also assigned the same 220 MW to Port Westward 2 when evaluating its ability to provide flexible capacity.[4]

As noted above, as an operational matter, Port Westward 2 cannot meet all capacity purposes simultaneously. Its capability will be limited at varying times and by varying degrees by operational choices PGE makes in order to reliably supply power in a least-cost manner.

Ability for Port Westward 2 to Integrate VERs (Including Wind) – Questions (b), (d), (f)

In assessing PGE's supply and demand balance for flexible capacity, PGE does not solely analyze the integration of VERs. Rather, PGE evaluates load net of VERs.

- Increases in load net of VERs require PGE to have the ability to rapidly ramp up energy production (i.e., up ramp requirements). Increases in load net of VERs pose a reliability and economic risk to PGE.

- Decreases in load net of VERs require PGE to have the ability to (1) rapidly ramp down production from its flexible capacity resources or (2) decrease the output from its VERs (i.e., down ramp requirements). Decreases in load net of VERs pose an economic risk to PGE (low marginal dispatch cost, lost production tax credits, etc.), because PGE can curtail generation from its wind facilities.

As shown in Chapter 5 of PGE's 2013 IRP, PGE's portfolio of dispatchable resources (including Port Westward 2) is capable of meeting up ramp requirements in 2015 resulting from PGE's load net of the Biglow Canyon and Tucannon River wind projects.[5]

However, with respect to down ramp requirements, PGE would not be able to meet all load net of wind (i.e., Biglow Canyon and Tucannon River projects) events in 2015. However, as described above, the deficit of down ramp requirement is an economic risk (but not a reliability risk) due to PGE's ability to curtail wind generation.

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[3] PGE's 2009 IRP was acknowledged by Commission Order No. 10-457 on November 23, 2010. PGE's Energy and Capacity RFP was approved by the Commission in June 2012.
[4] For the purposes of PGE's flexible capacity analysis in its 2013 IRP, PGE assumed Port Westward 2 was not running at the start of an event, meaning the power plant makes no contribution to down ramp in PGE's analysis.
[5] PGE's IRP filings are available at: www.portlandgeneral.com/irp.

June 17, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 511
Dated June 4, 2014

Request:

Regarding PGE's response to Staff Data Request 001 in Docket No. UE286, part "a," where the Company represented:

> ***"PGE is continuing to work toward the least cost, least risk option for integrating wind. The fourth quarter of 2015 is the next available date for which PGE could elect self-integration or some other combination of services for wind resources, if PGE has the necessary infrastructure and systems in place"***

And,
Given the fact that Port Westward 2 was conceived in PGE's 2009 Integrated Resource Plan,[1] was selected in a 2012 Request for Proposal,[2] and started construction in May 13, 2013,[3]
Please respond the following questions:

a. If available, how much time did the Company estimate it would take to have the necessary infrastructure and systems in place to self-integrate wind at the following points in time?
   i. Approximately five years ago when Port Westward 2 was conceived;
   ii. Approximately two years ago when Port Westward 2 was selected;
   iii. Approximately one and a half year ago when Port Westward 2 started construction;
   iv. As of the date of filing the current rate case proceeding in Docket No. UE283 (i.e., February 2014); and

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[1] See Exhibit UE 283/PGE/400, Pope - Lobdell/2, lines 19-20.
[2] See Exhibit UE 283/PGE/400, Pope - Lobdell/3, lines 3-4.
[3] See Exhibit UE 283/PGE/400, Pope - Lobdell/26, Table 2.

v. **As of the date of responding this data request.**

b. **What actions have the Company taken since Port Westward 2 was conceived approximately five years ago to have the necessary infrastructure and systems in place to self-integrate wind?**

Response:

PGE objects to this request to the extent that it calls for speculation and is based on inaccurate assumptions and/or incomplete premise. Notwithstanding this objection, PGE responds as follows:

The timing for self-integration is informed by multiple issues, many of them external to PGE such as the evolving BPA rates/products, regional issues and market solutions. PGE's internal process to evaluate the costs, benefits and risks associated with comparing self-integration against BPA offered products, in particular Variable Energy Resource Balancing Service (VERBS) rate, began with the development of PGE's Biglow Canyon wind farm.

From that point on, PGE's decision to self-integrate proceeded on a parallel path with its process to (1) identify a need for flexible capacity resources and (2) fill the identified need. In addition, PGE also developed multiple Wind Integration Study phases; participates in BPA's 30/30 pilot program; conducted the Renewable and Flexible Capacity Requests for Proposals; and explored (and continues to explore) Energy Imbalance Market (EIM) based solutions. These paths do intersect and the decisions made at each significant point were submitted along the way as part of various regulatory processes.

As demonstrated, PGE's strategy to self-integrate wind is not focused exclusively on utilizing Port Westward 2. Instead, integration of wind resources is conducted on a portfolio basis. As discussed with OPUC Staff, CUB and ICNU during the last several years, and most recently during UE 266 workshops leading up to PGE's election to continue with BPA VERBS 30/60 in April 2014, PGE is taking a systematic and methodical approach in its strategy for wind integration, including potential self-integration. PGE's next opportunity to evaluate self-integration is the BPA April 2015 election for the period of October 2015 to October 2017.

Please refer to PGE's Response to OPUC Data Request No. 510 regarding the contractual restrictions and potential penalties on PGE's ability to terminate VERBS before October 2015.

Integrated Resource Plan (IRP)

PGE's IRP was initially filed in November 2009 identifying a need for capacity resources including 200 MW of flexible capacity:

"PGE requests acknowledgement of up to 200 MW of flexible capacity resources by year-end 2013 to fill a dual function of providing capacity to maintain supply reliability during peak demand periods and providing needed flexibility to address variable load requirements and increasing levels of intermittent energy resources."[4]

PGE's IRP was acknowledged by Commission Order No. 10-457 on November 23, 2010. As noted in the excerpt above, PGE sought a resource that would provide capacity for peak demand and load following, not just integration of variable energy resources.

Request for Proposals (RFP)
To fill the need identified in the IRP, PGE initiated a Capacity RFP process. In the Capacity RFP, PGE sought a resource that would provide both peaking and flexible capacity to meet the needs identified in the Commission acknowledged action plan. This RFP allowed for a broad array of potential resources to meet the stated need. The Capacity RFP process initially started in March 2011, and was refiled at the direction of the Commission (Order No. 11-371). The Capacity RFP was approved as a combined Energy and Capacity RFP in June 2012, following public involvement in the drafting of the RFP.

In accordance with Order No. 07-002, Guideline 13.a. required PGE to "identify any Benchmark Resources it plans to consider in competitive bidding". As stated in the IRP, and further disclosed in the RFP, PGE intended to submit benchmark bids in the 2012 RFP. See Draft RFP page 18. To that end, the IRP and RFP identified PGE's proposed benchmark resources. PGE's capacity benchmark resource was supported by two different technologies, and one of the bids was determined to offer the lowest cost and least risk alternative for customers.

The RFP was conducted with oversight by the Independent Evaluator who was appointed by the Commission pursuant to the OPUC's Competitive Bidding Guidelines. Port Westward 2 was selected as the highest scoring flexible capacity resource bid in the RFP on January 31, 2013. The Independent Evaluator's report concluded that the RFP was conducted in a fair and transparent manner consistent with the OPUC's Competitive Bidding Guidelines.

Port Westward 2
PGE selected the Port Westward 2 bid and it is under construction and is expected to be completed on-budget by January 2015. Please refer to PGE's Response to OPUC Data Request No. 001 in UE 286 for a discussion of the benefits provided by Port Westward 2 included in PGE's 2015 test year forecast.

BPA's 30/30 Committed Intra-Hour (CIH) Pilot Program
During the CIH Pilot Program PGE participated in the Interchange Transaction Accelerator Project (ITAP), which is a trading platform designed to facilitate a sub-

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[4] Page 325 of PGE's 2009 IRP (dated November 5, 2009). PGE's IRP filings are available here: www.portlandgeneral.com/irp.

hourly energy and capacity market. The sub-hourly market was underdeveloped and not liquid. Due to the lack of a liquid sub-hourly market and the existing hourly bi-lateral market structure of the Northwest, PGE relied substantially on its own system to balance intra-hour load and wind variations. This experience helped PGE to identify several areas within PGE's traditional system operations model that are in need of expansion and development. See Dynamic Dispatch Program below for information on PGE's efforts to address these areas.

Please refer to Attachment 511-A for additional information regarding PGE's participation in BPA's 30/30 CIH Pilot Program beginning in October 2011. Attachment 511-A is PGE's Response to OPUC Data Request No. 009 in Docket No. UE 266 (PGE's 2014 net variable power cost filing).

Wind Integration Study (Wind Study)
Leading up to and in parallel with the 2009 IRP process, PGE conducted a Wind Study to estimate the cost of self-integrating its variable energy resources. PGE has continued to develop its Wind Study during the last several years and recently submitted Phase 4 with its 2013 IRP Report. Attachment 511-B is an excerpt from Appendix D to PGE's 2013 IRP Report that summarizes PGE's Wind Study efforts from 2007 to present.

Dynamic Dispatch Program
After gaining experience with sub-hourly scheduling of wind resources, PGE organized the efforts of three integration-related efforts under the Dynamic Dispatch Program:

1. PI Consolidation – this project began in early 2012 to consolidate current generating plant PI systems and expand a centralized PI system to include data from all generating plants. This combined data source will then be used by plant management and Power Operations to perform daily business functions.
2. Cycling Cost Studies & Automated Generation Control (AGC) Telemetry Installation – this work also began in early 2012. PGE is conducting studies on PGE's thermal resources to determine their cycling capabilities and the costs associated with using them for integration (wear and tear, forced outage rates, etc.). Based on the outcome of the cycling cost studies, PGE will install AGC at appropriate thermal plants.
3. Dynamic Dispatch Tool – this project creates/purchases a tool(s) that can simultaneously optimize the PGE system for reliability requirements and economic dispatch of the plants. This will support PGE's ability to 1) self-integrate wind, 2) participate in an EIM, and 3) automatically dispatch plants more efficiently to load.

All of this work is expected to be completed prior to October 1, 2015.

In parallel with the work described above, PGE also monitors developments such as sub-hourly scheduling and EIM markets. A combination of any of these processes could yield additional cost-effective tools for integrating VERs.

In summary, PGE developed an IRP that identified the need for peaking capacity as well as flexible capacity to follow load and integrate wind. An RFP was conducted and resulted in the selection of Port Westward 2, which will provide both peaking and flexible capacity to meet customers' identified needs. In addition, PGE continues to refine its Wind Integration Study, and participate in the sub-hourly scheduling and EIM markets while evaluating the requisite infrastructure and systems for integration. The level of maturity of these steps will help inform PGE's election on wind integration in April 2015.

UE 283

Attachment 511-A

Provided in Electronic Format only

UE 266, PGE's Response to OPUC Data Request No. 009

UE 283

Attachment 511-B

Provided in Electronic Format only

PGE 2013 IRP Excerpt Regarding Wind Study

Exhibit 1805

Attachments to PGE Response to OPUC Data Request No. 511

Provided Electronically Only

PPA, enabling access to the Northwest market, enabling redirects to meet other transmission needs to ensure reliability, and for path management.

Q. Was it prudent for PGE to renew the 531 MW Beaver PTP Contract through 2020?

A. Yes. Without the Beaver PTP Contract, PGE would not have sufficient transmission rights to deliver generation to load, we would be more limited in our access to energy markets, and our ability to maintain a reliable system for our customers would be reduced significantly. By renewing the 531 MW Beaver PTP Contract, PGE ensured that the generation from our resources and contracts would be reliably delivered to our system, that we have access to Northwest markets, and that we are able to maintain future roll-over rights on the 531 MW Beaver PTP Contract to continue to support PGE's generation and transmission portfolio.[4]

B. Wind Integration

Q. Please summarize ICNU's proposal regarding wind integration.

A. ICNU proposes that PGE model its 2015 NVPC to reflect the estimated net benefit of self-integration as if PGE had elected to self-integrate Biglow Canyon and Tucannon for the April 2014 BPA mid-rate-period election. This 2014 election would mean that PGE would self-integrate beginning October 1, 2014, through September 30, 2015.

Q. What election did PGE make for the April 2014 mid-rate-period election?

A. As part of the BP-14 BPA rate case, BPA allowed VERBS customers to make a mid-rate-period election in April 2014 for service beginning on October 1, 2014, and ending on September 30, 2015. PGE decided to not self-integrate its wind for the reasons we discuss

[4] According to BPA's Reservation Priority, Version 9 business practice, "All subsequent Renewal Requests received on or after October 3, 2008 must be for five years or longer for the Renewal Request to have Reservation Priority rights..."

below. As a consequence, PGE elected the 30/60 committed scheduling option for BPA's VERBS for both Biglow Canyon and Tucannon.

Q. Can you please briefly explain BPA's VERBS and 30/60 committed scheduling?

A. Yes. Currently, Biglow Canyon Wind Farm is a part of BPA's Control Area. When Tucannon begins operations it will also be a part of BPA's Control Area. Under BPA's Tariff, BPA offers VERBS to customers with Variable Energy Resources (VERs), such as wind, within BPA's Control Area. VERBS provides capacity reserves for regulating, following, and imbalance:

- <u>Regulating</u> reserves are held for the moment-to-moment differences between generation and load.
- <u>Following</u> reserves are held for the larger differences that occur over longer periods of time within the hour.
- <u>Imbalance</u> reserves are held for differences between scheduled and actual generation for the hour.

Under the 30/60 committed scheduling option, PGE submits a schedule 30 minutes before the next hour for the forecast of the plant's output during the next hour. The forecast is based on BPA's persistence forecast, which is the one minute average of generation from 29 to 30 minutes after the current hour. For example, PGE would submit a schedule for Biglow Canyon at 2:30 pm for generation that will occur from 3:00 pm to 4:00 pm. The schedule is based on a forecast that is derived by taking the average of Biglow Canyon's generation from 2:29 pm to 2:30 pm.

Q. Can you please briefly explain what ICNU is referring to as self-integration in their testimony?

A. Yes. In the context of ICNU's testimony, self-integration means Biglow Canyon and Tucannon would be metered as if they were located within PGE's Control Area and PGE would be solely responsible for all variations in generation (i.e., no longer a part of BPA's Control Area and not being integrated by BPA VERBS). In order to manage this variation, PGE would need to hold additional reserves on our generators that would be capable of responding to the three types of differences (i.e., regulating, following, and imbalance) and be able to change the output of those generators accordingly with minimal notice.

Q. In practice, is it required that PGE self-integrate all aspects of both Biglow Canyon and Tucannon?

A. No. PGE can choose to self-supply wind integration services in whole or in part. For instance, we could elect to have a certain phase of one of our wind farms integrated through BPA and could self-integrate the others. In the past, BPA had offered the wind integration choice as an "either/or" scenario: either integrate fully through BPA or fully self-integrate or procure from a third party. We could also choose to self-supply generation imbalance while continuing to rely on BPA to provide the others. PGE continues to evaluate the available options and pursue the least-cost, least-risk option for our customers.

Q. Why did PGE elect to continue to use BPA VERBS 30/60 committed scheduling?

A. There were three major drivers that led PGE to elect BPA VERBS 30/60 committed scheduling:

1) The long period required for development, implementation, and testing of necessary systems, software, and equipment;
2) Integration of wind must be accomplished at the portfolio level; and,

3) Uncertainty regarding available election options and developing markets, specifically a robust sub-hourly market.

Q. Can you provide more detail on the first driver identified above regarding necessary systems, software, and equipment?

A. Yes. PGE participated in BPA's 30/30 Committed Intra-Hour (CIH) Pilot Program during October 1, 2011 through September 30, 2013. The 30/30 CIH Pilot Program required participants to schedule their wind generation with BPA on a 30-minute basis rather than the standard hourly basis. PGE's participation in the 30/30 CIH Pilot Program helped us identify areas within our traditional system operations model that we must develop and expand in order to successfully move toward self-integration.

The 30/30 CIH Pilot Program also identified a need for PGE to determine the operational abilities of each generation asset, specifically thermal plants, and the impacts of increased movement and cycling on these assets. After our experience with sub-hourly scheduling of wind resources, PGE began to develop a plan that included the installation of Automatic Generation Control (AGC) on additional generation assets, improved data and communication systems, and dynamic load and dispatch tools. PGE is currently in the process of implementing this plan under the Dynamic Dispatch Program (DDP). The DDP consists of the following sub-projects:

- Plant Data (PI) Consolidation – Consolidates current generating plant PI systems and expands a centralized PI system to include data from all generating plants.
- Cycling Cost Studies & AGC Telemetry Installation – PGE is conducting studies on PGE's thermal resources to determine their cycling capabilities and the costs associated with using them for integration (wear and tear, forced outage rates, etc.).

Based on the outcome of the cycling cost studies, PGE will install AGC at the appropriate thermal plants.

- Dynamic Dispatch Tool – Develop a tool(s) that can simultaneously optimize the PGE system for reliability requirements and economic dispatch of the plants. This will support PGE's ability to (a) self-integrate wind, (b) schedule wind sub-hourly, (c) participate in an EIM, and (d) automatically dispatch plants more efficiently to load.

Exhibit 201 contains a timeline of the DDP. Given the complexity of the DDP, it will not be completed in time for the October 1, 2014 VERBS start date that corresponds to the April 2014 mid-rate-period election due to the extensive work and testing needed to ensure reliable service and to minimize the risk to various systems and generation assets. We expect the DDP to be completed by October 1, 2015.

Q. Please provide more detail on the second driver identified above regarding integration of wind at the portfolio level.

A. Integration of wind requires a coordinated effort across PGE's entire resource portfolio due to the high and rapid variability of wind and the increasing amount of wind generation in PGE's portfolio.[5] Once PGE elects to self-integrate wind, PGE's Control Area Operator will be solely responsible for maintaining the reliability of PGE's system given the increased variability due to wind. Without proper preparation of PGE's systems, additional AGC capable generating facilities, and sufficient balancing resources, PGE and its customers would be exposed to significant costs and risk for non-compliance with industry and region reliability standards. Port Westward 2 is only one of the resources required to manage the

[5] Tucannon will add approximately 267 MW of wind to PGE's system.

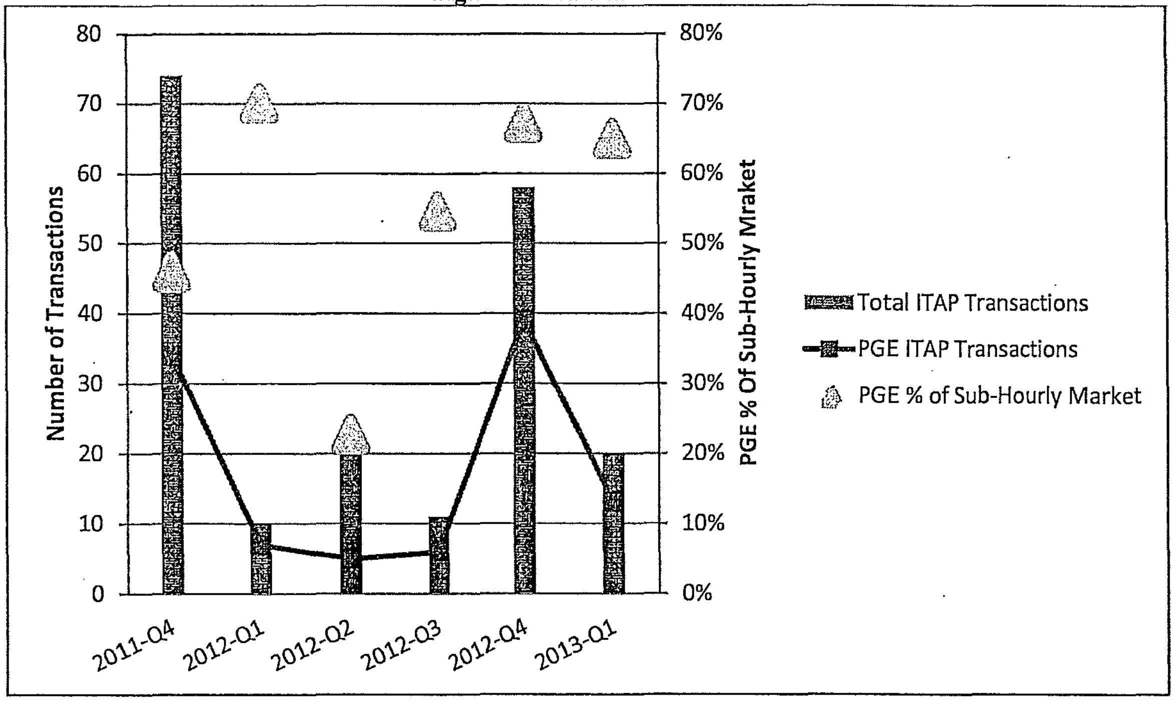
variability of load and the increased variability of wind to ensure efficient and reliable operation of PGE's Control Area. Although Port Westward 2 is a highly flexible resource, it is not the singular balancing resource, but rather an important piece in PGE's generation fleet. In order to ensure a coordinated effort across PGE's portfolio, AGC must be installed on more generation assets and the operating range of each generation resource must be accurately determined. Advanced tools are needed to plan and coordinate the dispatch of generation assets. As stated above, these are the primary tasks of the DDP, which PGE is currently implementing.

Q. Please provide more detail on the third driver identified above regarding uncertainty.

A. During the 30/30 CIH Pilot Program, PGE participated in the Interchange Transaction Accelerator Project (ITAP), which is a trading platform designed to facilitate a sub-hourly energy and capacity market. We found that the sub-hourly market was underdeveloped and illiquid, with PGE representing a significant portion of the sub-hourly transactions that occurred.[6] Figure 2 below provides a quarterly summary of the total ITAP transactions and the percentage of those transactions involving PGE.[7]

[6] PGE continues to participate in ITAP and continues to represent a significant portion of the transactions that occur.
[7] Presented at the December 2013 UE 266 VERBS workshop.

Figure 2 - ITAP Transactions



As discussed at the UE 266 VERBS workshops, ITAP and the sub-hourly market continue to develop. Regional entities provided feedback to the ITAP vendor and entered into a trial in April 2014 to evaluate the available capacity in the region. This capacity trial showed significant weakness in the sub-hourly market and ITAP. The ITAP vendor has since determined that significant revamping of ITAP is required and will be implementing changes throughout 2014 and 2015. Without an efficient market and scheduling platform, sub-hourly market participation and scheduling is exceptionally difficult for a region that traditionally relies on hourly bilateral scheduling. As a result, there is an increased reliance and strain on system resources to manage increased variability due to wind generation.

Q. How does a sub-hourly market help to integrate wind?

A. Currently, the Northwest market is an hourly market with a bi-lateral structure. An hourly market is used to integrate wind by allowing participants, such as PGE, to engage in transactions that reduce the hour-to-hour variability of wind resources by procuring the necessary capacity or energy for each hour. By definition, the hourly market is unavailable within the hour and requires participants to use their own resources, regardless of economics, to integrate the within hour variability of wind generation. A sub-hourly market facilitates transactions within the hour that can be used to manage the system impact of wind variability during other periods of the hour and allows participants to make the most economic choice for integrating wind within the hour. During the 30/30 CIH Pilot Program, PGE participated in ITAP to access the sub-hourly market, but due to the lack of liquidity in the sub-hourly market and the existing hourly bi-lateral market structure of the Northwest, PGE had to rely substantially on its own system to balance intra-hour load and wind variations.

Q. Was the sub-hourly market the only source of uncertainty PGE was facing at the time of the April 2014 mid-rate-period election?

A. No. At the time of the April 2014 mid-rate-period election, it was unclear if BPA would be able to permit 15-minute scheduling on their system. In addition, the necessary BPA business practices were not developed or vetted nor would they be available for comment or review until after the mid-rate-period election. As discussed at the March UE 266 VERBS workshop, PGE could not explicitly model the 15-minute VERBS scheduling option because of the significant policy unknowns and as such represented a substantial risk.[8] PGE also faced uncertainty regarding the developing Energy Imbalance Markets (EIM) in the Northwest, such as the requirements for participation, business practices, regulation, and what role an EIM would play in wind integration.

[8] Confidential Exhibit 202 provides the presentation from the March 2014 VERBS workshop. The presentation was also provided by ICNU in Confidential Exhibit ICNU/102.

Q. Did PGE discuss the available election options, its analysis of those options, the results of the analysis, the drivers identified above, and its final election with interested Parties?

A. Yes. In the stipulation reached in our last AUT filing (Docket No. UE 266), PGE agreed to meet with parties at least twice to present our analyses regarding the April 2014 mid-rate-period election.[9] PGE presented both quantitative and qualitative analyses regarding the topics outlined in the stipulation and discussed these major drivers in detail with other Parties in that docket including ICNU, OPUC Staff, and CUB.[10]

Q. Has PGE had sufficient time to develop the systems needed for self-integration?

A. No. As we stated above, integrating wind resources is accomplished through a coordinated effort using a portfolio of resources. Several necessary systems, equipment, and tools must be developed, upgraded, tested, and implemented in order to ensure reliability and the effective coordination of PGE's generation resources, communication and data systems, power operations personnel, and Control Area personnel. Following PGE's participation in BPA's 30/30 CIH Pilot Program, PGE began final development of a plan, the DDP, which would coordinate and facilitate the work needed to develop, upgrade, test, and implement the necessary systems, equipment, and tools. PGE began participation in BPA's 30/30 CIH Pilot Program in the fourth quarter of 2011. As PGE gained experience with the 30/30 CIH Pilot Program and the sub-hourly market, PGE began work on initial projects, which would later be consolidated into what is now the DDP, in the first quarter of 2012. PGE anticipates completing and implementing all phases of the DDP by October 1, 2015, in time for the next BPA rate period.

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[9] UE 266 Stipulation Pg. 3-4
[10] Exhibit 203 provides the presentation from the December 2013 VERBS workshop. See Confidential Exhibit 202 for the March 2014 VERBS presentation.

Q. Was the sole function of Port Westward 2 to integrate PGE's wind resources?

A. No. PGE's 2009 Integrated Resource Plan (IRP) identified a need for capacity resources including 200 MW of flexible capacity:

> "PGE requests acknowledgement of up to 200 MW of flexible capacity resources by year-end 2013 to fill a dual function of providing capacity to maintain supply reliability during peak demand periods and providing needed flexibility to address variable load requirements and increase levels of intermittent energy resources."[11]

PGE's IRP was acknowledged by the Commission on November 23, 2010. As stated in the excerpt above, PGE sought a resource capable of providing capacity for peak demand <u>and</u> load following, not just the integration of variable energy resources.

Q. Is Port Westward 2 able to integrate all of PGE's wind resources?

A. No, not by itself. PGE's ability to integrate wind requires more resources than Port Westward 2. As stated above, the integration of wind resources is conducted on a portfolio basis and requires a coordinated effort. As we discussed with OPUC Staff, CUB, ICNU, and RNP during the UE 266 BPA VERBS workshops, PGE is taking a systematic and methodical approach to prepare for wind integration beginning in October 2015.

Q. When is the next election opportunity for BPA VERBS?

A. The next BPA VERBS election will be April 2015 for service beginning on October 1, 2015 and ending on September 30, 2017. At this time, BPA is in the workshop phase of developing their BP-16 Rate Case and has not decided if it will offer an April 2016 mid-rate-period election opportunity for service beginning on October 1, 2016 and ending on September 30, 2017.

Q. Is PGE preparing its systems and resources?

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[11] PGE's 2009 IRP (dated November 5, 2009.), pg. 325.

A. Yes. PGE is currently developing and implementing the necessary systems, equipment, and operational procedures for integrating wind into PGE's Control Area. PGE included an estimate of the integration benefits for the fourth quarter of 2015 in our April 1 NVPC update filing because October 1, 2015, is the earliest date that PGE can make a change to its current BPA VERBS election. Also, by October 1, 2015, PGE will have approximately eight months of operational experience with the reciprocating engine technology at Port Westward 2 and anticipates completing DDP by that date.

Q. Was PGE's decision to elect 30/60 committed scheduling for the April 2014 mid-rate-period election prudent?

A. Yes. PGE elected the 30/60 committed scheduling option for the BPA VERBS April 2014 mid-rate-period election for the following reasons:

1) The development, implementation, and testing of necessary systems, software, and equipment was not complete in time for the mid-rate-period election;
2) Integration must be accomplished at the portfolio level; and,
3) There was significant uncertainty regarding available election options and developing markets.

Q. Is it appropriate to model NVPC for the entire 2015 test year based on self-integration?

A. No. As discussed in our previous response, 30/60 committed scheduling was the prudent election for October 2014 through September 2015. PGE is continuing to pursue the least-cost, least-risk option for integrating its wind resources; however, as detailed above, several processes must be completed and implemented in order to ensure reliable service for customers and prudently manage risk.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
201	Dynamic Dispatch Program Timeline
202C	March 2014 VERBS Workshop Presentation
203	December 2013 VERBS Workshop Presentation

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Tax

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Brett Greene

July 16, 2014

Table of Contents

I. Introduction

Q. Please state your name and position with Portland General Electric ("PGE").

A. My name is Brett Greene. My position is Director of Treasury and Tax in the Corporate Finance Department. My qualifications are included in PGE Exhibit 1100.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the testimony of the Industrial Customers of Northwest Utilities (ICNU) on deferred production tax credits (PTCs).

Q. What specific issues will you address?

A. I will address the following four issues:

- ICNU believes PGE can utilize all the PTCs generated from both the Tucannon River Wind Farm (Tucannon) and the Biglow Canyon Wind Farm (Biglow) in the test year based on PGE's normalized tax forecast.[1] I will demonstrate PGE's methodology provides the most benefit for customers and that PGE is unable to utilize all of its expected generated PTCs.
- ICNU states customers do not receive tax benefits associated with accelerated depreciation.[2] I will show PGE customers have and will continue to receive substantial tax benefits associated with accelerated depreciation under PGE's methodology.
- ICNU claims customers are not receiving an appropriate level of tax benefits from PTCs due to PGE using accelerated depreciation for Tucannon and Biglow.[3] I will show that PGE customers are receiving the benefits of PTCs generated consistent with the constraints of PGE's expected taxable income.

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[1] UE 283 ICNU/100/Mullins/14
[2] UE 283 ICNU/100/Mullins/16-17
[3] UE 283 ICNU/100/Mullins/16-17

- ICNU testifies that normalized tax reflects the requirement in Internal Revenue Code (IRC) § 168(f)(2) that prohibits a utility from including the deferred tax benefits associated with accelerated depreciation in rates.[4] I will explain how ICNU misinterprets and misapplies IRC § 168(f)(2).

[4] UE 283 ICNU/100/Mullins/16

II. ICNU Issues

A. PGE's PTC Utilization Calculation

Q. Why is PGE not utilizing all of the PTCs generated in the test year?

A. PGE is unable to utilize all of its PTCs generated during the test year in large part due to accelerated depreciation from Tucannon River Wind Farm (Tucannon).

Q. Is ICNU's statement correct that "in no circumstance should the average rate base associated with a potential deferred production tax credit asset for Tucannon in the test period exceed greater than one-half of the amount generated in the test period"?[5]

A. No. This statement does not consider the impact of Tucannon on PGE's base business (which includes PTCs generated at Biglow). PGE estimates that the base case (i.e., not including Tucannon or Port Westward 2) could utilize all of the PTCs generated in 2015 including the carryover of unutilized PTCs from 2014. However, when Tucannon's full impact is added to the base case, PGE's utilization of PTCs declines due to the impacts of accelerated depreciation on taxable income. The base case has a deferred PTC balance that represents the forecasted 2014 ending balance. The Tucannon portion of the filing has a balance that is the average of the 2014 and 2015 balances related to Tucannon. In summary, due to unutilized PTCs prior to the test year and the inclusion of Tucannon's impact, PGE has a deferred tax asset for PTCs in excess of Biglow and Tucannon's PTCs generated in the test year. Table 1 and 2 below illustrate Tucannon's impact on utilized PTCs. In particular, note that the inclusion of Tucannon reduces utilization of PTCs in both 2014 (impacting the December 31, 2014 balance used for base business) and 2015.

[5] UE 283 ICNU/100/Mullins/17, lines 11-13

Table 1
2015 Base Case Deferred PTC Calculation ($000)

	2014 PTC Average Balance	2015 PTC Generation	2015 PTC Utilization	2015 PTC Average Balance
Biglow	23,186	28,785	(51,971)	-
Total	23,186	28,785	(51,971)	-

Table 2
2015 Base & Tucannon Case Deferred PTC Calculation ($000)

	2014 PTC End Balance	2015 PTC Generation	2015 PTC Utilization	2015 PTC Average Balance
Biglow	29,579	28,785	(25,742)	32,642
Tucannon	748	19,757		20,505
Total	30,327	48,542	(25,742)	53,127

Q. Can you demonstrate that PGE will not be capable of utilizing the entire amount of PTCs in the test year?

A. Yes. Table 3 below demonstrates how Tucannon's impact on PGE's base case decreases our PTC utilization due to the impacts of accelerated depreciation on taxable income.

Table 3
Production Tax Credit Utilization ($000)

	2015 (Test Year)	Reference	Base Case	Tucannon + Base
a	Current Taxes		81,629	34,315
b	Deferred Taxes		-	-
c	Taxes Payable	*a + b*	81,629	34,315
d	Tax payable in excess of $25,000	*c - $25k*	81,604	34,290
e	25% of tax payable in excess of $25,000	*d * 25%*	20,401	8,572
f	PTC utilization limit (IRC §45(c)(1)(B))	*d - e*	61,203	**25,742**
g	Tucannon PTC		-	19,757
h	Biglow PTC		28,785	28,785
i	PTC carryover from 2014		23,186	30,327
j	Total PTC	*g + h + i*	51,971	**78,869**
k	PTC utilized	*Min(f,k)*	51,971	25,742
l	Deferred Tax Asset (credit carry forward)	*j - k*	-	**53,127**

As mentioned previously, PGE estimates that the base case could utilize all of the PTCs generated in 2015 including the carryover of unutilized PTCs from 2014. However, when Tucannon is added to the base case, PGE's utilization of PTCs declines due to the impacts of accelerated depreciation on taxable income.

B. PTC Benefits in Conjunction with Accelerated Tax Depreciation

Q. Did PGE include the tax benefits associated with the PTCs generated by Tucannon and Biglow in the test year forecast?

A. Yes. Customers receive a current tax benefit associated with the estimated PTCs as they are generated through a direct reduction to current income tax expense in the revenue requirement calculation. The reduction is provided even though PGE cannot use all of the generated PTCs on an expected basis in 2015. This can be seen in PGE's updated revenue requirement in PGE Exhibit 1701. Table 4 provides a 'snap shot' of PTC benefits as included in PGE's revenue requirement tax calculation for the test year forecast.

Table 4
PTC Benefit in Revenue Requirement ($000)

		Base Business 2015	PW2	Tucannon	Total Results
		(1)	(2)	(3)	(4)
	Utility Income Taxes				
54	Book Revenues	1,730,311	49,050	40,354	1,819,716
55	Book Expenses	1,440,886	13,354	16,963	1,471,203
56	Interest Deduction	80,578	8,688	13,764	103,029
57	Production Deduction	-	-	-	-
58	Permanent Ms	(20,679)	(645)	(627)	(21,951)
59	Deferred Ms	(58,125)	6,196	71,740	19,811
60	Taxable Income	287,652	21,457	(61,485)	247,624
61	Current State Tax	21,901	1,634	(4,681)	18,854
62	State Tax Credits	(3,009)	-	-	(3,009)
63	Net State Taxes	18,892	1,634	(4,681)	15,845
64	Federal Taxable Income	268,760	19,823	(56,804)	231,779
65	Current Federal Tax	94,066	6,938	(19,881)	81,123
66	**Federal Tax Credits**	**(28,929)**	**-**	**(19,757)**	**(48,686)**
67	ITC Amort	-	-	-	-
68	Deferred Taxes	(23,221)	2,475	28,659	7,914
69	Total Income Tax Expense	60,809	11,047	(15,660)	56,195

Q. Do customers pay PGE's cost of capital on unutilized PTCs?

A. Yes. PGE is unable to utilize all estimated PTCs generated from Tucannon and Biglow in the test year. As mentioned previously, the estimated PTC benefit is provided to customers in the 2015 revenue requirement. Customers are receiving a cash benefit in the form of a revenue requirement reduction before PGE receives a corresponding cash benefit (i.e., reduced tax liability) from the federal government. In other words, PGE is making a payment to customers and must wait for a period of time before it receives payment from the government. Therefore, it is reasonable for customers to pay PGE's cost of capital on the unutilized PTCs.

C. Customer Benefits Associated with Accelerated Tax Depreciation

Q. Do customers receive benefits from accelerated tax depreciation?

A. Yes. Contrary to what ICNU claims,[6] while there is no income tax expense benefit to customers due to normalization, there is a benefit from the accumulated deferred income tax liabilities created.[7] These liabilities significantly reduce PGE's rate base, thereby reducing PGE's revenue requirement. Included in PGE's filing are approximately $600 million worth of deferred tax liabilities related to accelerated depreciation, which reduce PGE's revenue requirement by approximately $68.6 million.

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[6] ICNU/100, Mullins/16 - 17

[7] Generally in the first few years of a property's life, the tax impacts from accelerated depreciation create a current tax benefit and an equal and offsetting deferred tax expense. The deferred tax expense creates a deferred tax liability, which is included as a reduction to rate base.

Q. Can PGE opt out of accelerated depreciation?

A. No. PGE has three choices for how to depreciate wind farms for tax purposes that are all accelerated relative to depreciation for book purposes: 1) 5-year Modified Accelerated Cost Recovery System (MACRS), 2) 5-year straight-line or 3) 12-year straight-line.

Q. Which of these methods did PGE choose and why?

A. PGE elected 5-year MACRS for Biglow Canyon Wind Farm and will do so again for Tucannon because it is the best election for PGE's customers. Under the two alternatives (5-year straight-line and 12-year straight-line), customers would end up paying more for the same resource. Table 5 below, demonstrates PGE's use of 5-year MACRS to be significantly more beneficial to customers than the alternative methods.

Table 5
Present Value Revenue Requirement Comparison ($millions)

	MACRS (5-year)	5-Year Straight-line	12-Year Straight-line
Net Present Value of Revenue Requirement	$769.7	$784.6	$991.2

For this example PGE assumed a generic wind farm costing $500 million, with a 27-year book life and annual PTC generation of $20 million. The calculations are provided in work papers.

D. Normalization Requirements

Q. Is ICNU's testimony correct in stating that normalized tax reflects the requirement in IRC Section 168(f)(2) that prohibits a utility from including the deferred tax benefits associated with accelerated depreciation in rates?[8]

[8] ICNU/100, Mullins/16

A. No. Although IRC Section 168(f)(2) does not allow for an income tax expense benefit in revenue requirement, it does require a reduction in rate base, which is a benefit to customers that PGE is providing. IRC Section 168(f)(2) allows a utility to utilize accelerated depreciation in calculating its current income tax, if it uses the normalization method of accounting.[9]

Q. Is ICNU's proposed methodology on normalized taxes clear regarding PTC utilization?

A. No. ICNU uses the term "normalized taxes" throughout their testimony; however, their proposal would not normalize taxes. Due to the uncertainty surrounding ICNU's proposed methodology, we discuss three different possible interpretations of ICNU's testimony and their consequences.

1. If ICNU's proposed methodology is to normalize PTCs throughout the revenue requirement, is this required by the Internal Revenue Code (IRC)? Would PGE customers receive a benefit?

No, this treatment is not required by the IRC. However, this approach would yield sub-optimal results for customers because it would unnecessarily increase PGE's revenue requirement and therefore customer prices. Currently, customers receive the benefit of PTCs in the year of generation through a reduction to PGE's current tax expense. If PTCs are normalized throughout the revenue requirement model, the benefit would be spread over the life of the plant. For example, the 2015 Biglow estimated PTCs of $28.8 million would not reduce current tax expense as it does now. The PTCs would be recorded as a regulatory

[9] The normalization rules are defined in IRC Section 168(i)(9).

liability and amortized over the remaining life of the plant (approximately 19 years), yielding a benefit of just $1.5 million.

2. If ICNU's proposed methodology is that the deferred tax expense should be considered in conjunction with current tax expense, is this appropriate?

No, this is not appropriate. PTCs are utilized based on the current federal tax liability as calculated on the federal income tax return. PTCs are based upon the cash expended for federal income tax; they are not based on the total of current and deferred tax expense as suggested by ICNU's model.

3. If ICNU's proposed methodology is that the deferred tax expense should be considered in conjunction with current tax expense, would PGE customers receive a benefit?

No, PGE customers would not receive a benefit. Deferred tax expense is currently a benefit which, if combined with current tax expense, would reduce the amount of PTCs that could be utilized. This would result in the increase of the deferred PTCs balance, increasing rate base and therefore increasing PGE's revenue requirement.

III. Conclusion

Q. Please summarize PGE's position on the reasonableness of ICNU's proposed adjustment.

A. PGE disagrees with ICNU's proposed adjustment and the Commission should reject it. First, customers receive the full benefit of PTCs in the year of generation through a reduction in current tax expense. Second, PGE customers are receiving the benefit of accelerated depreciation through a rate base reduction. Third, PGE customers should pay carrying costs on the unutilized PTCs as PGE has given the customers the upfront benefit of PTCs as generated and before PGE receives the benefit from the federal government. Lastly, PGE believes normalization of PTCs throughout the revenue requirement would be detrimental to customers as the benefit would be spread over the life of the plant and would increase PGE's revenue requirement. PGE's filed case represents the best results for customers within the constraints of our expected 2015 taxable income. Regardless of interpretation, ICNU's proposal represents poor tax planning and would result in unnecessary revenue requirement increases for customers.

Q. Does this conclude your testimony?

A. Yes.

UE 283 / PGE / 2000
Villadsen

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Return on Equity

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Bente Villadsen

July 16, 2014

Table of Contents

I. Introduction and Summary

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

A. My name is Bente Villadsen and I am a principal at The Brattle Group (Brattle). My business address is The Brattle Group, 44 Brattle Street, Cambridge, MA 02138, USA.

Q. Please summarize your background as it pertains to this matter.

A. I have more than 15 years of experience consulting on regulatory finance for regulated infrastructure companies in the electric, natural gas, railroad, water and wastewater industries. I have provided expert reports and testified on cost of capital in many jurisdictions including state regulatory settings, Bonneville Power Authority, U.S. and international arbitrations, U.S. federal court, and in Australia, Canada, Italy, and the Netherlands. This work has pertained to electric utilities, pipelines, railroads, telecommunications, water and wastewater utilities. Examples of my recent cost of capital work include reports or testimony on the cost of capital methodology for Australian pipelines before the Australian Energy Regulator, cost of equity for regulated U.S. water utilities and a Canadian pipeline in arbitration. I am an instructor at Edison Electric Institute's Advanced Rate School teaching "Current Issues in Cost of Capital." I hold a Ph.D. from Yale University and joint MS and BS degrees in mathematics and economics from University of Aarhus, Denmark. My full resume is provided as PGE Exhibit 2001.

Q. What is the purpose of your rebuttal testimony?

A. I have been asked by Portland General Electric (PGE) to review the direct testimony of Dr. Thomas M. Zepp (Zepp Testimony) on behalf of PGE, the Opening Testimony of Michael P. Gorman (Gorman Testimony) on behalf of Industrial Customers of Northwest Utilities (ICNU), the Opening Testimony of Matt Muldoon (Staff Testimony) on behalf of the

Oregon Public Utility Commission and to (i) provide a recommendation regarding the reasonableness of the recommendation of the Zepp Testimony and PGE's requested return on equity (ROE) and (ii) comment on the Gorman Testimony and Staff Testimony.

Q. Did you file direct testimony in this case?

A. No. Direct Testimony on cost of capital was filed by Dr. Thomas M. Zepp (Zepp Testimony) on behalf of Portland General Electric. I adopt his recommendation and comment on why the ROE recommendation of 10.5% is reasonable below.[1]

Q. What are your views on Dr. Zepp's Direct Testimony and PGE's request?

A. I agree with Dr. Zepp's recommendation that a reasonable range for the cost of equity for an integrated electric utility is 9.9% to 10.6% and that PGE faces more risk than the average of his sample. Therefore, the Zepp Testimony's recommendation of 10.5% ROE is reasonable. In fact, I believe that PGE's request for an ROE of 10% is in the low end of what is reasonable, given PGE's higher than average risks.

Q. Please summarize your rebuttal testimony.

A. First and foremost, I find the recommendation of Dr. Zepp and the request of PGE to be consistent with the current evidence on cost of equity. I believe PGE's requested ROE is in the low end of what is currently reasonable given PGE's risk profile. Second, neither the Staff Testimony nor the Gorman Testimony considers PGE-specific risks that indicate PGE's cost of equity is above that of the samples' averages. The recommended ROE is therefore downward biased. Third, the Staff Testimony does not consider information from models other than the multi-stage DCF model, which causes the testimony to ignore

[1] I note that in connection with the California Public Utilities Commission's three year review of water utilities' cost of equity and capital structure, Dr. Zepp and I both appeared as witnesses for the water utilities and agreed on the magnitude of the ROE. See the consolidated docket A.11-05-001 to A.11-05-004.

information from current market conditions. Fourth, the Staff Testimony compares its recommendation to the allowed ROE during Q1, 2014 and eliminates Virginia-specific generation ROEs, which are higher than that national average.[2] However, if unique ROE allowances for generation facilities are to be eliminated, it is also necessary to eliminate the allowed ROEs for the distribution and transmission only entities, which are not comparable to PGE. Doing so results in an allowed ROE average of 10%, which is comparable to the allowed ROE for all electric utilities and similar to PGE's requested ROE. Fifth, there are a number of technical details in the Gorman Testimony and Staff Testimony that are misguided. I comment on those in the last section.

In summary, if I correct Staff's and Gorman's ROE estimates and take the PGE-specific risk into account, the modified ROE estimates confirm the range obtained by Zepp and PGE's ROE request is well within the estimated ranges.

[2] OPUC Exhibit 200, pp.18-20.

II. Why the Recommendation of Dr. Zepp and PGE's Request are Reasonable.

Q. Please summarize the recommendations of all witnesses.

A. The *estimated* ROE and the recommended ROE is shown in Table 1 below.

Table 1: Estimate and Recommended ROEs

		Range for ROE			Recommended ROE
Company Request	[1]	NA		NA	10.0%
Zepp Testimony	[2]	9.9%	-	10.6%	10.5%
Staff Testimony	[3]	8.8%	-	9.6%	9.2%
Gorman Testimony	[4]	8.6%	-	10.1%	9.4%

Sources and Notes:
[1]: UE 283 General Rate Case- PGE Exhibit 1200, p.2
[2]: Ibid, p.1
[3]: OPUC Exhibit 200, p.20
[4]: ICNU Exhibit 200, pp. 20, 26, 31-32

Regarding the recommendations, I note several factors that bias Staff's recommendation downward: (i) Staff relied exclusively on a multi-stage DCF model, (ii) Staff inappropriately eliminates generation incentive ROE but no other non-comparable decisions when considering the recently allowed ROE for electric utilities, (iii) Staff selected a group of smaller entities and ignored utilities that may be appropriately comparable companies, and (iv) Staff has some technical errors in their analysis.[3] If I revise Staff's estimates to take the factors above into consideration, the revised estimates are 25 to 67 basis points higher. Mr. Gorman estimated an ROE of 9.05% using his DCF models, 9.70 % using his risk premium

[3] For example, Staff calculated the growth rate from 2011-13 to 2016-18 based on the historical forecasted EPS for 2011-13 rather than the realized EPS. Because 2012 EPS on average were lower than expected and growth rates have been updated to take this into account, the relied upon growth rates are downward biased. For Staff's model Y, the ROE would be up to 25 basis points higher had the realized EPS for 2012 been used instead of the forecasted EPS.

model and 9.60% using his capital asset pricing model (CAPM).[4] Two of his three methodologies result in an ROE above the recommended 9.4% and had Mr. Gorman relied upon the average from his models or the median from those models, his recommendation would increase to 9.5% or 9.6%. Further, the Gorman Testimony contains some technical errors that bias the estimates downward. If I correct the technical errors, the estimation results increase to about 9.7% to 9.9%. Taking the unique risks into account either by adding a number of basis points or using the high end of the estimates results in an estimate of about 9.9%.

Neither Staff nor Gorman considers the risk of PGE relative to the selected sample companies. Overall, I consider the recommendations of both Staff and Gorman too low.

Q. Please comment on Dr. Zepp's recommendation.

A. I find the estimated range of 9.9% to 10.6% to be reasonable in the current environment. It is consistent with what has recently been awarded to other electric utilities and given PGE's unique risks from a large construction program and relative large reliance on power purchase agreements, PGE should be placed towards the upper end of the range. Further, the estimation techniques relied upon by Dr. Zepp are commonly used in regulatory cost of capital proceedings. I agree with Dr. Zepp assessment that PGE's requested ROE of 10.0% is conservative for several reasons. It is towards the lower end of the range estimated by Dr. Zepp and slightly below the average ROE allowed for electric utilities in Q1, 2014 and for utilities in the comparable samples.[5]

Q. What other preliminary comments do you have on the sample selections and estimation techniques relied upon in the testimonies of Zepp, Staff, and Gorman?

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[4] ICNU Exhibit 200, p. 32.

[5] Regulatory Research Associates, *Major Rate Case Decisions – January – March 2014*, April 9, 2014.

A. First, I would point out that Mr. Gorman adopts Dr. Zepp's sample of 20 electric utilities (the Zepp / Gorman sample). In contrast, Staff relies on a sample of only eight electric utilities (Staff sample) of which only four overlap the Zepp / Gorman sample. Second, while the Zepp Testimony takes PGE-specific characteristics into account, neither the Staff nor the Gorman Testimony considers the risks specific to PGE. Third, the estimation techniques differ substantially. The Zepp Testimony as well as the Gorman Testimony relies on several different model types that use different types of information, while the Staff Testimony relies exclusively on multi-stage DCF models. Specifically, the Zepp Testimony relies on constant growth, two-stage and three-stage DCF models along with three versions of the risk premium model. Because Dr. Zepp relies on both DCF and risk premium models, he captured information from company-specific forecasts, industry, and market conditions. In contrast, Staff's Testimony referenced only the three-stage DCF models and therefore the relied-upon information is less broad. The Gorman Testimony relies on versions of the constant growth, sustainable growth, and multi-stage DCF models as well as two versions of the risk premium and the CAPM Model. The technical details of the relied-upon models and the impact of specific choices on the estimated ROE are discussed in Section VI below.

III. Intervenors' Failure to Consider PGE-Specific Risk.

Q. Please explain what specific risks PGE faces.

A. While there are several company-specific risk factors, I shall focus on three key risks: (i) PGE has a large capital expenditure program relative to its peers, (ii) PGE needs to rely more heavily on Power Purchase Agreements (PPA) than the sample companies, and (iii) PGE is smaller than the companies in Staff's sample. These three characteristics increase PGE's risk.

Q. Why do large capital expenditures increase risk?

A. Fundamentally, the "true cost of capital depends on project risk, not on the company undertaking the project."[6] A company engaged in a large capital expenditure program, especially if the capital expenditures pertain to new projects, is weighing its portfolio of capital investments towards newer (less tried and true) projects that have risks, and hence, a cost of capital that is higher than that of established capital projects. This is due to the risks inherent in completion, operation, and integration of these projects. Therefore, a company that is engaged in a relatively large capital expenditure program will have higher risk. Credit rating agencies such as Standard & Poor's (S&P) recognize that PGE has significant financial risk and cite the ongoing capital expenditure program as one reason.[7]

Q. How does PGE's capital expenditure compare to that of comparable companies?

A. PGE Exhibit 2002 shows capital expenditures (CapEx) as a percentage of net property, plant and equipment (net PPE) for all companies in the Zepp / Gorman sample and for Staff's sample. It is clear from PGE Exhibit 2002 that PGE has relatively higher capital

[6] Richard A. Brealey, Stewart C. Myers, and Franklin Allen, *Principles of Corporate Finance, 10th Edition, 2011,* p. 215.
[7] Standard & Poor's RatingsDirect, Portland General Electric Co., May 8, 2014.

expenditures than the sample companies in the Zepp / Gorman or the Staff samples. While the average and median CapEx to net PPE is 10% for the Zepp / Gorman sample, PGE has a ratio of 16%, which indicates substantial investments in new PPE. Staff's sample is comparable to the Zepp / Gorman sample with an average CapEx to net PPE ratio of 11%. Thus, PGE is investing substantially more in new PPE than the sample companies and a large portion pertains to new generation, which will reduce the company's reliance on power purchases going forward.[8]

Q. Please explain how PPAs increase risk.

A. PPAs are obligations to pay a third party as are bonds and other debt. Therefore, these contracts have debt-like characteristics and are disclosed in the notes to the financial statements along with other third party obligations.[9] Because these obligations have features similar to debt, they increase the leverage of the company even if they are not included in the calculation of debt using balance sheet data.[10] PPAs are treated as a type of debt obligation by credit rating agencies, which may impute debt to utilities that have long-term PPAs. The amount of debt that credit rating agencies impute from PPA obligations depends on (i) the characteristics of the PPA, and (ii) the regulatory recovery of the costs associated with the PPA. In the case of PGE, the imputed interest expense from PPAs is non-trivial. Because of the debt-like nature of PPAs, they impose financial risk on the buying company (and transfers risk away from the seller). The only way many independent power producers can obtain financing for a new power plant is if they have signed long-term PPAs for the output, i.e., if they have transferred some of the risk to the purchasing utility. Financial

[8] Portland General Electric Company, 2013 Annual Report, indicates an investment of $1.25 billion in generation assets ("2013 Accomplishments") and that a substantial portion of its current investment pertains to generation (pp. 43 and 55).
[9] See, for example, Portland General Electric Company, 2013 Annual Report, p. 59.
[10] Currently, Generally Accepted Accounting Principles do not require all PPAs to be included on the balance sheet.

institutions such as S&P explicitly recognized the financial risk that PPAs carry,[11] and implicitly, so does the Gorman Testimony, which shows that if S&P's method for imputing PPA debt to PGE is used, then the debt ratio increases from 50% to 53.4%.[12] Thus, the financial leverage and, hence, the financial risk increases, which causes the cost of equity to increase. If PGE were to maintain the same overall rate of return when the debt percentage is 53.4% as under the rate making capital structure that has 50% debt, the ROE will need to increase. Gorman's recommendation of 9.4% for 50% regulatory equity[13] translates into an ROE of about 9.7% if the debt percentage increases to 53.4%.[14]

Q. Can you illustrate the magnitude of PGE's PPAs?

A. Yes. First, as shown in PGE Exhibit 2002, PGE has generation to service a little under half of its electric sales and therefore needs to purchase power. In contrast, the companies in the Zepp / Gorman as well as in Staff's sample, on average have sufficient generation to service approximately 68% of their load.[15] Thus, PGE currently has relatively less generation than the sample companies. The magnitude of PGE's reliance on PPAs is also evident from PGE's annual report, which shows that PPAs account for a large portion of its long-term obligations and especially so over the next few years.[16] Specifically, the PPAs account for 22% to 39% of total long-term obligations over the next three years.[17]

Q. Are there other PGE-specific risk factors?

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[11] See also, Michael J. Vilbert, Bente Villadsen, and Joe Wharton, Understanding Debt Imputation Issues, published by Edison Electric Institute, June 2008

[12] ICNU Exhibit 218, p.1

[13] ICNU Exhibit 202, p.1

[14] Gorman in ICNU Exhibit 202, p.1 calculates the weighted average cost of capital as:

$$50\% \times 9.4\% + 50\% \times 5.50\% = 7.45\%$$

The same weighted cost of capital is obtained at 53.4% debt using an ROE of 9.68%, *e.g.*,

$$(1\text{-}53.4\%) \times 9.68\% + 53.4\% \times 5.50\% = 7.45\%.$$

[15] The median is a little higher, so there is no obvious single company that drives the results.

[16] Portland General Electric Company, 2013 Annual Report, p. 59.

[17] *Ibid*, p. 59.

A Yes, the companies in Staff's sample are larger than PGE. For example, the market capitalization for half of Staff's sample companies is above \$5 billion and categorized as large cap companies. In contrast, Value Line finds that PGE has a market capitalization of only \$2.5 billion and towards the low end of the mid-cap companies.[18]

Q. Why does the size of PGE matter?

A. Empirically, investors have required a higher premium to invest in smaller companies than in larger ones. For example, Morningstar / Ibbotson data indicate that mid-cap companies (\$2 - \$5 billion in market capitalization) on average have a return on equity that is 1.14% higher than that of large companies.[19] Therefore, empirical evidence suggests that investors in smaller and mid-cap companies require a higher return than do investors in larger companies. To put the magnitude in perspective, Dr. Zepp suggested an upward adjustment of 0.20% for PGE, while empirical data suggest that the size effect is more than five times larger. As a result, the selection of relatively larger companies plausibly biases the cost of equity estimate downwards.

Q. What conclusions do you draw from the discussion above?

A. There are several reasons why PGE has a higher level of risk than the comparable companies. It is important to recognize the relative risk of the targeted entity (PGE) versus that of the sample companies used to determine the ROE. Because PGE is more risky along several dimensions, I find that PGE should be placed in the upper end of the reasonable range and, therefore, an ROE of about 10.5% as recommended by Dr. Zepp is warranted. Consequently, I recommend that the Commission grant PGE its requested ROE of 10%.

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[18] Value Line Investment Survey, May 2, 2014 and June 20, 2014 list Allete, Cleco, IDACORP, and Westar as mid-cap companies, while AEP, DTE, Edison International and PG&E are listed as large cap.
[19] Morningstar / Ibbotson, *2014 Classic Yearbook*, p. 109.

IV. Staff Fails to Consider Any Model Other than DCF

Q. How do Staff's models differ from those of Zepp in this case?

A. As noted above, the Zepp Testimony relies on constant growth, two-stage and three-stage DCF models along with three versions of the risk premium model. Of these, the DCF models use primarily forward looking information, while the risk premium models use primarily historical information. The models therefore capture different types of information. In contrast, Staff relies exclusively on versions of the three-stage DCF models. Thus, Staff's results are derived from versions of the same model type and therefore use the same type of information. Staff's models (i) rely heavily on the company-specific growth rates, (ii) use only Value Line growth rates, and (iii) restrict the sample to eight companies, so the Value Line growth rates for these eight companies along with long-term GDP growth rate assumptions are what determine the cost of equity estimate. Because company-specific growth rates become crucial in Staff's model, sample selection and the exact determination of the growth rates become very important. For example, if the sample selection results in high-growth companies being excluded or low-growth companies being included, then the results are affected. I therefore take a closer look at the sample composition in Staff's Testimony.

Q. Can you provide an example of why sample composition is important in this case?

A. Yes, looking at Staff's implementation of their model using the Zepp / Gorman sample instead of Staff's sample results in an ROE that is higher by 10 to 60 basis points, i.e., while Staff's sample shows ROE estimates of 8.6% to 9.3%[20], the same model results in estimates

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[20] Work papers to OPUC Exhibits 202, 203

of 9.2% to 9.4% if the Zepp / Gorman sample is used.[21] I discuss the technical issues further below.

Q. Do you have any additional concerns?

A. Yes. Because Staff relies exclusively on versions of the DCF model, which is primarily a forward looking model, there is no need to exclude companies that may have had dividend reductions or other issues some years back. The information is simply not used, i.e., only companies that have yet to recover from specific issues merit exclusion. Similarly, Staff's sample selection criteria eliminates companies that have a rating higher than BBB+, which excludes A- entities such as Consolidated Edison, Vectren, Wisconsin Energy, and Xcel. The elimination of investment grade entities that merely have a higher rating than PGE may result in the elimination of successful entities. This feature could potentially bias the results as lower rated entities tend to have lower growth and also may have unique circumstances that could bias the cost of equity estimation. I, therefore, consider the impact on Staff's results from allowing all investment grade companies to be part of the sample provided they fulfill all other criteria defined by Staff. I consider the impact of Staff's sample selection in Section VI below.

[21] These results are reported in PGE Exhibit 2004.

V. The Allowed ROE for Electric Utilities Is Currently Around 10%.

Q. How does Staff use allowed ROEs?

A. Staff notes that the average allowed ROE for 2013 was 10.03% and then excludes Virginia generation cases to obtain an average of 9.75% without the Virginia generation cases. Staff then states that the upper end of its 8.8% to 9.6% range overlaps the national average for Q1, 2014 if the Virginia generation cases are excluded.[22]

Q. Do you agree with Staff's analysis?

A. No. The analysis is flawed for two reasons. First, looking at only Q1, 2014 data without Virginia is a very short period and with only five non-Virginia cases, no statistical inference can be drawn from the data.[23] Second and more importantly, if Staff wants to place restrictions on companies whose data are included in the analysis, the restrictions need to be applied equitably. Specifically, if data for entities that obtain generation incentives are not relevant, then neither are data for entities that are pure transmission and distribution companies. In other words, only companies that own generation should be included to be comparable to PGE.

Looking at the underlying data from SNL,[24] I determine the average allowed ROE for all electric utilities for the period January 1, 2013 to March 31, 2014. I also determine the allowed ROE for companies that own generation but are not subject to Virginia's generation incentives. It is simply not appropriate to exclude the Virginia incentive ROE cases but leave other non-comparable cases in the average. The results are shown in Table 2 below.

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[22] OPUC Exhibit 200, pp. 19-20.
[23] Regulatory Research Associates, *Regulatory Focus: Major Rate Case Decisions – January – March 2014*, April 9, 2014.
[24] SNL Financial is a subscription service that collects, standardizes, and provides access to corporate, financial, market, regulatory and other data. It publishes Regulatory Research Associates data on rate case decisions.

PGE Exhibit 2003 shows the allowed ROE for various subsets of companies over an extended period of time.

Table 2: Electric Utility Allowed ROE: 2013-2014

	2013-2014
All States	
Average	10.00%
Median	9.95%
Excl. VA	
Average	9.79%
Median	9.80%
Excl. T&D Only Companies	
Average	10.16%
Median	10.00%
Excl. VA and T&D Only Companies	
Average	9.95%
Median	9.95%

It is clear from Table 2 above, that if the allowed ROEs being considered are restricted to entities that are comparable to PGE in the sense that they own generation and do not receive generation incentives, the average ROE is right around 10%. As shown by Dr. Zepp, the allowed ROE for companies in the Zepp / Gorman sample has averaged 10.4% to 10.7% in recent years.[25] Thus, all evidence is that the allowed ROE for comparable companies is at least 10% and therefore the upper end of Staff's range is well below the national average when calculated properly.

[25] PGE Exhibit 1204

VI. Technical Details of the Models.

Q. What do you cover in this section?

A. I discuss a few important technical details in the Staff and Gorman testimonies that substantially affect the estimated cost of equity. I address Staff's Testimony in Section A and Gorman's testimony in Section B. The discussion focuses on key elements and is not intended to be exhaustive.

A. Comments on Staff's Testimony.

Q. What is your overall view of Staff's Testimony?

A. As is demonstrated in Staff's Table 1,[26] the combination of using only one model, a small sample and specific assumptions, causes Staff's ROE estimates to be too low. Further, Staff's focus on a select subset of allowed ROE is used to justify the low ROE; but once the national ROE is measured appropriately, as discussed above, it is clear that Staff's recommendation is substantially below the national average.

Q. What technical details in Staff's Testimony do you address?

A. First, Staff appears to base its earnings per share (EPS) growth rate on the difference between the forecasted EPS for the 2011-13 and 2016-18 periods.[27] However, the actual 2012 EPS is available and as of today, analysts have access to that data for the purpose of estimating the 2016-18 EPS. Therefore, it is preferable to use actual 2012 EPS as the basis for estimating the growth to 2016-18, which is what I do. Second, Staff excludes a number of investment grade companies because they have an A- rating, which results in the exclusion of companies that are comparable but simply have a credit rating slightly above

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[26] OPUC Exhibit 200, p. 2
[27] This is also how Staff calculates the growth in dividends.

PGE. As these companies also have a higher growth rate on average than Staff's sample companies, the results are downward biased. Third, Staff relies on a long-term growth (stage 3) rate of 5.02% to 5.78%. The lower end of the range is determined from four specific sources with one being measured incorrectly. I address these points below.

Q. Please explain why the lower end of Staff's forecasted long-term growth may be too low.

A. Staff obtains a range of potential long-term GDP growth rates, where the lower bound is determined using forecasts from the Energy Information Administration (EIA), Office of Management and Budget (OMB), Congressional Budget Office (CBO) and an estimate of historical GDP growth. There are two sources of downward bias in this approach. First, Staff uses growth rate forecasts from EIA, OMB, and CBO, but does not use, for example, Morningstar / Ibbotson's forecast of 5.48%.[28] Second and more importantly, Staff relies on a regression analysis to determine the historical growth in GDP. This is problematic because it underestimates the historical growth relative to what is measured using a simple arithmetic average, which is appropriate when used to determine forward-looking returns.

Q. Why is the arithmetic average the appropriate measure of the historical growth in GDP?

A. It is the ***expected growth*** in GDP rather than the ***past performance*** that is relevant for the purpose of determining the long-term performance of the sample companies. To see that the arithmetic average is an unbiased estimate of the future growth, consider the following simple example. Assume that the future is similar to the past and the growth rate in each

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[28] Morningstar / Ibbotson, *2013 Valuation Yearbook*, p. 52.

period is the result of a random draw from a distribution of possible growth rates.[29] What is our best estimate of the average growth rate given our observations? The average of the observed growth rates! This result is explained in detail in many textbooks including the finance text of Berg and Demarzo 2014 and the Morningstar / Ibbotson 2014 Yearbook.[30] Therefore, the appropriate measure of the historical growth rate is a simple average of the historically observed growth rates, which over the period considered by Staff is 5.63%.[31] Thus, I modify Staff's long-term growth rates from OPUC Exhibit 200, p. 13, Table 5 in the Table 3, below.

Table 3: Staff's Long-Term Growth Rates As Reported and As Revised

	As Reported			As Revised		
	Nominal Rate	Weight	Weighted Rate	Nominal Rate	Weight	Weighted Rate
EIA	4.89%	16.70%	0.82%	4.89%	12.50%	0.61%
OMB	4.61%	16.70%	0.77%	4.61%	12.50%	0.58%
CBO	4.55%	16.70%	0.76%	4.55%	12.50%	0.57%
Ibbotson			0.00%	5.48%	12.50%	0.69%
Historical	5.35%	50%	2.68%	5.63%	50%	2.82%
Composite			*5.02%*			*5.26%*
Historical			*5.35%*			*5.63%*
Top 10 Blue Chip			*5.78%*			*5.78%*

As can be seen from Table 3, the lower end of the long-term growth rates is about 25 basis points higher than assumed by Staff.

Q. What are the implications of modifying the lower growth rate?

[29] This assumption is also made as the growth rate is estimated using a regression analysis.
[30] Jonathan Berg and Peter Demarzo, "*Corporate Finance: The Core*," 3rd Edition, 2014, p. 326 and Morningstar / Ibbotson, *2013 Valuation Yearbook*, pp. 56-57.
[31] A simple average of the GDP growth rates as calculated from Bureau of Economic Analysis GDP data over the period 1980 to 2013 (matching Staff's estimation period).

A. If the lower bound on the growth rate becomes 5.26% (instead of Staff's 5.02%) and the historical growth rate is 5.63%, then Staff's lowest estimates increase by about 10 basis points.[32]

Q. Have you determined the impact of the other technical issues?

A. Yes. As noted above, Staff uses the forecasted EPS for 2011-13 to estimate the growth rate for 2016-18.[33] Given that 2012 actual EPS figures are available, the actual EPS figures should be used. I therefore recalculated Staff's growth rates using actual EPS figures for 2012 from Value Line. This had minimal impact on the results.

Q. Did you address the sample selection issue?

A. Yes. I revised Staff's sample to include entities that met Staff's criteria other than not having a credit rating above BBB+ and also included PGE. This resulted in the inclusion of six additional companies: Consolidated Edison, El Paso Electric, Vectren Corp., Portland General Electric, Wisconsin Energy Group, and Xcel Energy.[34] With the exception of Consolidated Edison, these companies are on average comparable to the rest of the sample regarding generation ownership to load and capital expenditure to net PPE. Because Consolidated Edison owns very little generation, I report any results both with and without Consolidated Edison.

Table 4 below summarizes the modifications that are needed to the ROE estimates in Staff's Testimony to adjust for the downward bias in the estimated long-term growth rates, sample selection issues, the use of estimates rather than actual 2012 numbers, and ensuring that the allowed ROE is measured appropriately.

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[32] Estimated by inserting 5.26% instead of 5.02% in Staff's Model X.
[33] Value Line Investment Survey reports EPS estimates for, for example, the period 2016-18. However, when I inquired about the year to which the estimate pertains, the response was that it pertains to the middle year. In the example, it is 2017.
[34] I also looked at whether any companies were cut due to older dividend reductions, but found none.

Table 4: Summary of Staff Original and Modified ROE Estimates

	As Reported	As Modified	As modified w/o Consolidated Edison
Multi-stage DCF, X (using historical growth)	8.69%	9.21%	9.20%
Multi-stage DCF, Y (using historical growth)	8.81%	9.42%	9.48%
Allowed ROE	9.75%	10.00%	10.00%
Min	8.69%	9.21%	9.20%
Max	9.75%	10.00%	10.00%
Median	9.22%	9.61%	9.60%
Midpoint	9.22%	9.61%	9.60%

Sources:
OPUC Exhibit 200 Workpapers, PGE Exhibits 2003 and 2004

Looking to Staff's data and recommendation, it appears that the recommendation of 9.2% is consistent with the midpoint of the estimated ROE and Staff's calculation of the allowed ROE without the Virginia generation ROEs. Having modified Staff's calculations and re-calculated the allowed ROE by ignoring not only generation-specific ROEs in Virginia, but also the allowed ROE for transmission and distribution-only utilities, I obtain a modified midpoint of 9.6%. If PGE's unique risks are considered, the estimate increases and is comparable to the low end of Dr. Zepp's range of 9.9%. While I think the low end of Dr. Zepp's range is too low for PGE, the analysis shows that once the technical issues in the Staff Testimony have been eliminated and PGE-specific risks are considered, then the estimates overlap Dr. Zepp's recommendation.

B. Comments on Gorman's Testimony.

Q. What technical details in the Gorman Testimony do you address?

A. First, I address Gorman's argument that the GDP growth is a conservative estimate for the long-term GDP growth. I also discuss Gorman's use of the sustainable growth model. Second, I address Gorman's reliance on a historical market risk premium of 6.1% rather than the Morningstar / Ibbotson historical market risk premium in his CAPM. The Morningstar / Ibbotson figure would result in a market risk premium of approximately 7%[35]. The lower market risk premium biases the estimated ROE downward. Third, I address Gorman's risk premium analyses, which rely on misguided allowed ROE figures and Gorman's analyses where the period over which the analysis is conducted may bias the results downward.

Q. Please explain the issue with Gorman's argument that the "U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility"?[36]

A. The Gorman Testimony compares the U.S. GDP nominal growth rate and the stock market growth using a geometric series, which measures the compounded growth over a period of time and therefore depends only on the beginning and ending value of the underlying indices (nominal GDP and the stock market index). There are two problems associated with using a geometric measure of growth for the purpose of determining the ROE. As discussed above, the arithmetic average is most appropriate in the context of determining the expected growth rate. The geometric average looks at the compounded growth that has been achieved over a specific time period and is appropriate when reporting the historical performance of, for

[35] Morningstar / Ibbotson *2014 Classis Yearbook*, p. 91.
[36] ICNU Exhibit 200, p. 17

example, an investor's 401(k) stocks over the last year. However, for the purpose of determining the cost of equity for PGE over the next period, a forward-looking measure is required. We are interested in the expected growth over the next many years, not the performance over the last decade. It can be shown statistically that the geometric return of a series biases the expected return downward.[37] Second, the statistical characteristics of the U.S. nominal GDP and the U.S. stock market are different. Most notably, the stock market tends to be much more volatile than is the nominal GDP. Therefore, the comparison is not meaningful in a statistical sense and one has to be careful interpreting the results.

Q. What is the impact of Mr. Gorman's reliance on the nominal GDP growth in stage 3 of his multi-stage DCF model?

A. If the Gorman Testimony had relied on, for example, the historical long-term GDP growth of 5.63% as estimated above,[38] the average and median multi-stage DCF estimates increase by about 60-65 basis points as shown in below.

Table 5: Gorman Multi-Stage DCF Results and Modified Multi-Stage DCF Results

	Original results (4.7% growth rate)		*Revised results (using 5.63% GDP growth rate)*	
Description	*Average*	*Median*	*Average*	*Median*
Multistage Growth DCF Model	8.67%	8.60%	9.35%	9.27%

Sources:
ICNU Exhibit 200 Table 2, PGE Exhibit 2004

Q. Do you have any other comments on Gorman's DCF results?

[37] Morningstar / Ibbotson, *2013 Valuation Yearbook*, p. 66 shows that the arithmetic average of a series can be approximated as follows:

Arithmetic Average = Geometric Average + Variance of the Series / 2.

Because the variance is a positive number, the arithmetic average is larger than the geometric average.

[38] See Table 3 above.

A. Yes. Gorman also reports results from a sustainable growth model that estimates the growth rate as the sum of two components. The first component corresponds to internal growth and is based on the percentage of the utility's earnings that is retained in the company to fuel future growth while the second component is based on external earnings growth, which originates from issuing shares at above book value. The model runs into problems when companies engage in share buybacks. When a company buys back shares, the external growth in the model is negative, so that the growth rate is reduced. At the same time, investors receive early cash distributions (from the sale of shares), but the model fails to take this cash distribution into account - the model values the stock as if there was no distribution to shareholders from the buyback. Because the estimated ROE increases with the assumed distribution to shareholders, the model's failure to account for share buybacks biases the results downward when buybacks occur. In this case, Wisconsin Energy has undertaken a share buyback[39]. Therefore, the sustainable growth DCF estimates are biased downward. I have not estimated the impact of this effect.

Q. Why do you think Gorman's historical market risk premium is too low?

A. The Gorman Testimony uses the average of two market risk premium estimates derived from Morningstar / Ibbotson data. I will address only the second estimate, which is determined as the difference between the historical average return on the stock market (12.1%) and the historical total return on long-term government bonds (5.9%), so that the difference of 6.2% is the estimated market risk premium.[40] The problem with this derivation is that Gorman relies on the total return of the long-term government bonds, whereas the

[39] Wisconsin Energy Corporation, Investor Presentation, August 2013, p. 26.
[40] ICNU Exhibit 200, pp. 28-29.

only truly risk-free portion of the return is the income return. The authors of the text relied upon in the Gorman Testimony makes this clear:

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate horizon treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return and the reinvestment return… *The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.* (emphasis added)[41]

Q. What is the effect of the downward bias in the relied-upon market risk premium?

A. Using the total return on the long-term government bonds, Gorman obtains a CAPM estimate of the ROE of 9.36%.[42] However, had Gorman instead used the approach recommended by Morningstar / Ibbotson, the resulting CAPM ROE would be 10% as shown in Table 6 below.

Table 6: Gorman's Estimated CAPM ROE and As Modified CAPM ROE

Description	*High Market Risk Premium*	*Low Market Risk Premium (As Reported)*	*Low Market Risk Premium (As Revised)*
Risk-Free Rate	4.40%	4.40%	4.40%
Risk Premium	6.96%	6.20%	7.00%
Beta	0.80	0.80	0.80
CAPM	**9.97%**	**9.36%**	**10.00%**

Because Gorman uses the approach of averaging his two CAPM ROE estimates, the CAPM estimate for ROE increases from 9.63%[43] to 9.99% once the Low Market Risk Premium has been revised as suggested in the text relied upon by Gorman.

Q. Do you have any comments on the Gorman Testimony's Risk Premium Method?

[41] Morningstar Ibbotson, *2013 Valuation Yearbook*, p. 55.
[42] ICNU Exhibit 217.
[43] *Ibid.*

A. Yes. The Gorman Testimony uses the difference between the allowed ROE for electric utilities and 20-year treasury bond yield or between the allowed ROE and the yield on A-rated utilities to assess the risk premium that electric utilities need over the bond yield. There are two problems with Gorman's implementation of this model. First, Gorman selectively eliminate the allowed ROEs that originate from Virginia's generation incentives, but does not eliminate other non-comparable awards such as those that pertain to transmission and distribution companies only. Second, there is no specific time period over which the risk premium theoretically should be determined and the relationship between the allowed ROE and the bond yield could change over time. Therefore, I modify the risk premium model in two ways: (i) I replace Gorman's calculated allowed ROE in recent years by the actual allowed ROE and (ii) I estimate the risk premium that results from varying the period over which it is estimated. I use Gorman's estimate of 4.40% for the 20-year government bond yield and his estimate of 4.87% for the A-rated utility bond yield in the table below.[44] The key results are presented below in Table 7.

Table 7: Gorman Risk Premium Results as Reported and as Modified

	As Reported		As Modified	
	Using T-Bonds	Using A-rated Utility Bonds	Using T-Bonds	Using A-rated Utility Bonds
1986 - 2014	9.75%	8.84%	9.82%	8.91%
Last 20 years			10.23%	9.28%
Last 15 years			10.50%	9.48%
Last 10 years			10.67%	9.84%

[44] Gorman in ICNU Exhibit 200 pp. 24-25 considered a range of estimates.

From Table 7 above, it is clear that Gorman's recommendation of 9.70% for the risk premium model is too low if the intention is to "provide 70% weight to the high-end" and "30% to the low-end."[45] If I assign 70% weight to the highest estimate of 10.67% and 30% to the low estimate of 8.91%, the estimated ROE is 10.1%.[46] Therefore, the risk premium estimates are low relative to what is currently allowed nation-wide and relative to what the data show.

Q. Can you summarize the needed adjustments to the Gorman Testimony?

A. Yes. Table 8 below, summarizes the modifications that are needed to the ROE estimates in the Gorman Testimony.

Table 8: Summary of Gorman as reported and Modified ROE Estimates

	As Reported	Modified Range		
DCF	9.05%	9.37%	-	9.42%
Constant Growth DCF	*9.47% - 9.49%*	*9.47%*	-	*9.49%*
Sustainable Growth DCF	*8.69 - 8.82%*	*na*	-	*na*
Multi-stage DCF	*8.59 - 8.67%*	*9.27%*	-	*9.35%*
Risk Premium	9.70%	10.00%	-	10.10%
CAPM	9.60%	9.99%	-	9.99%
Average of Models	9.45%	9.79%	-	9.84%

Sources:
ICNU Exhibit 200 Tables 1, 2, 3, PGE Exhibit 2004

As is evident from Table 8 above, only Gorman's DCF estimates support an ROE as low as 9.4% and if implemented appropriately, Gorman's models and data support a midpoint of about 9.8%. Further, PGE should be placed towards the upper end of the range, so that the

[45] ICNU Exhibit 200, p. 25.

[46] Ignoring the last row in the Table 7 (Last 10 years) to be conservative, the estimated ROE is 10.0% using the 70-30 weighting.

data indicate an appropriate ROE is at or above 10%.

Q. What do you conclude from the analysis above?

A. Based on my review of the submitted testimonies and the available evidence, a range of 9.9% to 10.6% is reasonable for PGE with the upper end being more appropriate because of PGE's specific risks. I also find Staff's Testimony and Gorman's Testimony have biased the cost of equity estimates downward by about 40 basis points and fail to consider PGE-specific risks for which approximately 20 basis points should be added. Therefore, Staff's recommended number, when properly revised indicates an ROE of 9.6% - 10.0% and Gorman's recommendation indicates an ROE of 9.8% - 10.1%. Therefore, I recommend that PGE be granted its requested ROE of 10%.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2001	Resume of Dr. Bente Villadsen
2002	Risk Characteristics of Sample Companies
2003	Awarded ROE for Electric Utilities
2004	Revised ROE Estimation Results for Staff and Gorman

BENTE VILLADSEN

Principal

THE Brattle GROUP

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. In the regulatory finance area, Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent accounting work, she has been involved in accounting disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions. Her testimonies and expert reports pertain to accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, she was a Professor of Accounting at the University of Iowa, University of Michigan, and at Washington University in St. Louis where she taught financial and cost accounting. She has also taught graduate classes in econometrics and quantitative methods. Dr. Villadsen also worked as a consultant for Risoe National Laboratories in Denmark.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit
  - Risk Management
  - Regulatory Advisory
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Credit Issues in the Utility Industry
- Damages
  - Stock Price Drop
  - Lost Profit

EXPERIENCE

Regulatory Finance

- On behalf of American Water, California Water, EPCOR, and electric utilities in the Northwest, Dr. Villadsen has testified on cost of capital in state regulatory proceedings and before Bonneville Power Authority. In recent proceedings, her testimony included an evaluation of the impact of the financial crisis on the cost of capital and well as testimony on credit metrics and the implication of being non-investment grade.
- On behalf of the Australian Pipeline Industry Association (APIA), she led a study and co-authored a report on cost of equity and debt estimation methods. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- Dr. Villadsen has authored or co-authored reports on rate of return in connection with a review of regulatory practice for both regulators and other parties. The reports were submitted to the Nederlands Competition Authority, the British Columbia Utilities Commission, the Canadian Transportation Agency, the Australian Energy Regulator, the Economic Regulation Authority of Western Australia, and the Communications Regulatory Authority of Italy.
- She has advised the private equity arm of two large financial institutions as well as an infrastructure company, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and

Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.

- In a matter before Bonneville Power Administration, Dr. Villadsen filed expert testimony on behalf of customers regarding the cost of capital for electric utilities and the appropriate discount rate to apply to a government entity's cash flows.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties.
- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance. Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.

- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.
- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).

Accounting and Corporate Finance

- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.
- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In an arbitration matter before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the

distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.

- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.
- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.
- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.
- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.

- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages

- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.
- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.
- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.
- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.
- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.
- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.
- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.

- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

PUBLICATIONS AND REPORTS

Report on "Cost of Capital for Telecom Italia's Regulated Business" with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* ("AGCOM"), March 2014. *Submitted in Italian.*

"Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century," (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

"Estimating the Cost of Debt," (with T. Brown), prepared for the Dampier Bunbury Pipeline and filed with the *Economic Regulation Authority*, Western Australia, March 2013.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, M.J. Vilbert, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the *Australian Energy Regulator* and the *Economic Regulation Authority*, Western Australia, February 2013.

"Calculating the Equity Risk Premiumand the Risk Free Rate," (with Dan Harris and Francesco LoPasso), prepared for *NMa and Opta, the Netherlands*, November 2012.

"Shale Gas and Pipeline Risk: Earnings Erosion in a More Competitive World," (with Paul R. Carpenter, A. Lawrence Kolbe, and Steven H. Levine), *Public Utilities Fortnightly*, April 2012.

"Survey of Cost of Capital Practices in Canada," (with Michael J. Vilbert and Toby Brown), prepared for *British Columbia Utilities Commission*, May 2012.

"Public Sector Discount Rates" (with rank Graves, Bin Zhou), *Brattle* white paper, September 2011

"FASB Accounting Rules and Implications for Natural Gas Purchase Agreements," (with Fiona Wang), *American Clean Skies Foundation*, February 2011.

"IFRS and You: How the New Standards Affect Utility Balance Sheets," (with Amit Koshal and Wyatt Toolson), *Public Utilities Fortnightly*, December 2010.

"Corporate Pension Plans: New Developments and Litigation," (with George Oldfield and Urvashi Malhotra), Finance Newsletter, Issue 01, *The Brattle Group*, November 2010.

"Review of Regulatory Cost of Capital Methodologies," (with Michael J. Vilbert and Matthew Aharonian), *Canadian Transportation Agency*, September 2010.

"Building Sustainable Efficiency Businesses: Evaluating Business Models," (with Joe Wharton and Peter Fox-Penner), *Edison Electric Institute*, August 2008.

"Understanding Debt Imputation Issues," (with Michael J. Vilbert and Joe Wharton and *The Brattle Group* listed as an author), *Edison Electric Institute*, June 2008.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," *Public Utilities Fortnightly*, August 2005 (with A. Lawrence Kolbe and Michael J. Vilbert).

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," (with A. Lawrence Kolbe and Michael J. Vilbert, and with "*The Brattle Group*" listed as author), *Edison Electric Institute,* April 2005.

"Communication and Delegation in Collusive Agencies," *Journal of Accounting and Economics,* Vol. 19, 1995.

"Beta Distributed Market Shares in a Spatial Model with an Application to the Market for Audit Services" (with M. Hviid), *Review of Industrial Organization*, Vol. 10, 1995.

SELECTED PRESENTATIONS

"Capital Investments and Alternative Regulation," *National Association of Water Companies Annual Policy Forum,* December 2013.

"Current Issues in Cost of Capital," *Edison Electric Institute Advanced Rate School*, July 2013.

"Accounting for Power Plant," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"GAAP / IFRS Convergence," *SNL's Inside Utility Accounting Seminar*, Charlotte, NC, October 2012.

"Current Issues in Cost of Capital," *Edison Electric Institute's Advanced Rate Course*, July 2012.

"International Innovations in Rate of Return Determination," *Society of Utility Financial and Regulatory Analysts' Financial Forum*, April 2012.

"Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics," 1.5 day seminar, EUCI, Atlanta, May 2012.

"Cost of Capital Working Group Eforum," *Edison Electric Institute webinar*, April 2012.

"Utility Accounting and Financial Analysis: The Impact of Regulatory Initiatives on Accounting and Credit Metrics," 1.5 day seminar, EUCI, Chicago, January 2012, Atlanta, May 2012.

"Issues Facing the Global Water Utility Industry" Presented to Sensus' Executive Retreat, Raleigh, NC, July 2010.

"Regulatory Issues from GAAP to IFRS," NASUCA *2009 Annual Meeting*, Chicago, November 2009.

"Subprime Mortgage-Related Litigation: What to Look for and Where to Look," *Law Seminars International: Damages in Securities Litigation*, Boston, May 2008.

"Evaluating Alternative Business / Inventive Models," (with Joe Wharton). *EEI Workshop, Making a Business of Energy Efficiency: Sustainable Business Models for Utilities*, Washington DC, December 2007.

"Deferred Income Taxes and IRS's NOPR: Who should benefit?" *NASUCA Annual Meeting*, Anaheim, CA, November 2007.

"Current Issues in Cost of Capital," (with M.J. Vilbert). *EEI Electric Rates Advanced Course*, Madison, 2005.

"Issues for Cost of Capital Estimation," (with M.J. Vilbert). *EEI Cost of Capital Conference*, Chicago, 2004.

"Discussion of 'Are Performance Measures Other Than Price Important to CEO Incentives?'" *Annual Meeting of the American Accounting Association*, 2000.

"Contracting and Income Smoothing in an Infinite Agency Model: A Computational Approach," (with R.T. Boylan) *Business and Management Assurance Services Conference*, Austin 2000.

TESTIMONY

Direct Testimony on the rate impact of the pension re-allocation and other items for Upper Peninsula Power Company in connection with the acquisition by BBIP before the Michigan Public Service Commission in Docket No. U-17564, March 2014.

Expert Report on cost of equity, non-recovery of operating cost and asset retirement obligations on behalf of oil pipeline in arbitration, April 2013.

Direct Testimony on the treatment of goodwill before the *Federal Energy Regulatory Commission* on behalf of ITC Holdings Corp and ITC Midwest, LLC in Docket No. PA10-13-000, February 2012.

Direct and Rebuttal Testimony on cost of capital before the *Public Utilities Commission of the State of California* on behalf of California-American Water in Application No. 11-05, May 2011.

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Case No. 11-00196-UT, May 2011, November 2011, and December 2011.

Direct Testimony on regulatory assets and FERC accounting before the *Federal Energy Regulatory Commission* on behalf of AWC Companies, ER11-13-000/Eli-1-3-000, December 2010.

Expert Report and deposition in Civil Action No. 02-618 (GK/JMF) in the *United States District Court for the District of Columbia*, November 2010, January 2011.

Direct Testimony, Rebuttal Testimony, and Rejoinder Testimony on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-10-0448, November 2010, July 2011, and August 2011.

Direct Testimony on the cost of capital before *the New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 09-00156-UT, August 2009.

Direct and Rebuttal Testimony and Hearing Appearance on the cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-09-0343, July 2009, March 2010 and April 2010.

Rebuttal Expert Report, Deposition and Oral Testimony re. the impact of alternative discount rate assumptions in tax litigation. *United States Court of Federal Claims*, Case No. 06-628 T, January, February, April 2009. (*Confidential*)

Direct Testimony, Rebuttal Testimony and Hearing Appearance on cost of capital before the *New Mexico Public Regulation Commission* on behalf of New Mexico-American Water in Docket No. 08-00134-UT, June 2008 and January 2009.

Direct Testimony on cost of capital and carrying charge on damages, U.S. Department of Energy, *Bonneville Power Administration*, BPA Docket No. WP-07, March 2008.

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Expert Report, Rebuttal Expert Report, and Hearing Appearance regarding investing activities, impairment of assets, leases, shareholder' equity under U.S. GAAP and valuation. *International Chamber of Commerce* (ICC), Case No. 14144/CCO, May 2007, August 2007, September 2007. (Joint with Carlos Lapuerta, *Confidential*)

Direct Testimony, Rebuttal Testimony, and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0491, July 2006, July 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, Supplemental Rejoinder Testimony and Hearing Appearance on cost of capital before the *Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0403, June 2006, April 2007, May 2007.

Direct Testimony, Rebuttal Testimony, Rejoinder Testimony, and Hearing Appearance on cost of capital before *the Arizona Corporation Commission* on behalf of Arizona-American Water in Docket No. W-01303A-06-0014, January 2006, October 2006, November 2006.

Expert report, rebuttal expert report, and deposition on behalf of a major oil company regarding the equity method of accounting and classification of debt and equity, *American Arbitration Association*, August 2004 and November 2004. (*Confidential*).

Risk Characteristics of Sample Companies

Summary of CapEx to PPE and Generation to Sales (MW) of Samples

	Zepp / Gorman Sample		Staff Sample	
	Generation as % of Total Sales	Capex as % of Net PPE	Generation as % of Total Sales	Capex as % of Net PPE
Allete Inc	67%	13%	67%	13%
Alliant Energy Corporation	57%	10%		
Avista Corp	51%	10%		
Black Hills Corp	37%	9%		
Cleco Corporation	83%	6%	83%	6%
CMS Energy Corporation	53%	12%		
Great Plains Energy Incorporated	86%	9%		
Hawaiian Electric Company, Inc.	NA	NA		
IDACORP.Inc	78%	7%	78%	7%
MGE Energy, Inc.	59%	14%		
NorthWestern Corp	29%	13%		
OGE Energy Corp.	79%	12%		
Pinnacle West Capital Corporation	78%	10%		
PNM Resources Inc.	83%	10%		
Portland General Electric Company	**46%**	**16%**		
SCANA Corporation	84%	11%		
TECO Energy, Inc.	95%	9%		
UNS Energy Corp	69%	10%		
Westar Energy Inc	86%	11%	86%	11%
Wisconsin Energy Corp	66%	6%		
American Electric Power Company Inc			65%	12%
DTE Energy Co			85%	11%
Edison International			44%	13%
PG&E Corporation			38%	18%
Average	68%	10%	68%	11%
Median	69%	10%	72%	12%

Source: SNL as of 6/25/2014

Awarded ROE for Electric Utilities

State	Company	Service	Date	Allowed ROE (%)
Arkansas	Entergy Arkansas Inc.	Electric	12/30/2013	9.30
Connecticut	United Illuminating Co.	Electric	8/14/2013	9.15
District of Columbia	Potomac Electric Power Co.	Electric	3/26/2014	9.40
Florida	Gulf Power Co.	Electric	12/3/2013	10.25
Florida	Tampa Electric Co.	Electric	9/11/2013	10.25
Georgia	Georgia Power Co.	Electric	12/23/2013	NA
Georgia	Georgia Power Co.	Electric	12/17/2013	10.95
Iowa	MidAmerican Energy Co.	Electric	2/28/2014	NA
Idaho	PacifiCorp	Electric	10/24/2013	NA
Illinois	Ameren Illinois	Electric	12/9/2013	8.72
Illinois	Commonwealth Edison Co.	Electric	12/18/2013	8.72
Kansas	Westar Energy Inc.	Electric	11/21/2013	10.00
Kentucky	Kentucky Power Co.	Electric	11/22/2013	NA
Louisiana	Entergy Gulf States LA LLC	Electric	12/16/2013	9.95
Louisiana	Entergy Louisiana LLC	Electric	12/16/2013	9.95
Massachusetts	Fitchburg Gas & Electric Light	Electric	5/30/2014	9.70
Maryland	Baltimore Gas and Electric Co.	Electric	12/13/2013	9.75
Maryland	Delmarva Power & Light Co.	Electric	9/3/2013	NA
Michigan	Upper Peninsula Power Co.	Electric	12/19/2013	10.15
Mississippi	Mississippi Power Co.	Electric	3/5/2013	9.70
North Carolina	Duke Energy Carolinas LLC	Electric	9/24/2013	10.20
New Hampshire	Liberty Utilities Granite St	Electric	3/17/2014	9.55
Nevada	Sierra Pacific Power Co.	Electric	12/16/2013	10.12
New York	Consolidated Edison Co. of NY	Electric	2/20/2014	9.20
Oregon	PacifiCorp	Electric	12/18/2013	9.80
Oregon	Portland General Electric Co.	Electric	12/9/2013	9.75
South Carolina	South Carolina Electric & Gas	Electric	9/18/2013	NA
Texas	Entergy Texas Inc.	Electric	5/16/2014	9.80
Virginia	Appalachian Power Co.	Electric	12/17/2013	11.40
Virginia	Appalachian Power Co.	Electric	11/25/2013	NA
Virginia	Kentucky Utilities Co.	Electric	11/25/2013	NA
Virginia	Virginia Electric & Power Co.	Electric	3/14/2014	11.00
Virginia	Virginia Electric & Power Co.	Electric	3/14/2014	12.00
Virginia	Virginia Electric & Power Co.	Electric	2/28/2014	11.00
Virginia	Virginia Electric & Power Co.	Electric	11/26/2013	10.00
Washington	PacifiCorp	Electric	12/4/2013	9.50
Washington	Puget Sound Energy Inc.	Electric	6/25/2013	9.80
Wisconsin	Madison Gas and Electric Co.	Electric	7/26/2013	NA
Wisconsin	Northern States Power Co - WI	Electric	12/5/2013	10.20
Wisconsin	Wisconsin Power and Light Co	Electric	6/6/2014	10.40
Wisconsin	Wisconsin Public Service Corp.	Electric	11/6/2013	10.20
Average authorized ROE (all)				*10.00*
Median authorized ROE (all)				*9.95*
Average authorized ROE (excl VA generation)				*9.79*
Median authorized ROE (excl VA generation)				*9.80*
Average authorized ROE (excl. T&D only)				*10.16*
Median authorized ROE (excl. T&D only)				*10.00*
Average authorized ROE (excl VA generation and T&D only)				*9.95*
Median authorized ROE (excl VA generation and T&D only)				*9.95*

Source: SNL, RRA rate cases through Q1, 2014.

MODIFICATIONS TO STAFF AND GORMAN MODELS

Staff Results Vs. Dividend Growth Calculated Using Actual 2012 Dividends & Revised Sample

	Staff Model X [1]	Staff Model Y [2]	Dividend Growth Using 2012 Actual EPS Model X [3]	Dividend Growth Using 2012 Actual EPS Model Y [4]
Staff Original Sample				
American Electric Power Company Inc	8.74%	9.01%	8.76%	9.09%
ALLETE Inc	8.41%	8.88%	8.41%	8.91%
Cleco Corporation	8.99%	9.27%	8.95%	9.19%
DTE Energy Co	8.77%	8.89%	8.82%	8.92%
Edison International	8.47%	8.11%	8.49%	7.79%
IDACORP Inc	9.02%	8.34%	9.05%	8.38%
PG&E Corporation	8.72%	9.35%	8.72%	9.56%
Westar Energy Inc	8.41%	8.64%	8.41%	8.56%
Revised Sample Additions*				
Consolidated Edison Inc			8.83%	8.30%
El Paso Electric Co			8.23%	8.37%
Vectren Corp			8.36%	9.75%
Portland General Electric			7.73%	9.16%
Wisconsin Energy Group			11.13%	11.28%
Xcel Energy Inc			8.89%	9.76%
Average	8.69%	8.81%	8.77%	9.07%
Average Without Consolidated Edison Inc			8.77%	9.13%

Sources and Notes:

[1]-[2]: Staff 203 X & Y Models

[3]-[4]: Uses 2012 actual dividends and earnings to calculate the initial stage growth rates rather than the average of 2011 actual, 2012 actual, and 2013 estimated dividends and earnings used in the Staff X & Y models respectively.

*: The revised sample additions include companies with A- debt ratings and are without dividend cuts in the last 2 years. The peer screen performed requires companies to have debt ratings of BB+ to BBB+ and be without a dividend cut in the last 5 years. All other screen criteria is the same.

Gorman's Model

Company	13-week average stock price [1]	Annualized Dividend [2]	Forecasted Dividend In Each Year 1 [3]	2 [4]	3 [5]	4 [6]	5 [7]	6 [8]	7 [9]	8 [10]	9 [11]	10 [12]	Terminal Value [13]	Terminal Value + Forecasted Dividend In Year 10 [14]	Difference In NPV and price [16]	Calculated discount rate [15]
ALLETE	$51.04	$1.96	-	-	-	-	-	-	-	-	-	-	-	- -	-	
Alliant	$56.00	$2.04	2.15	2.26	2.38	2.50	2.64	2.77	2.91	3.06	3.21	3.36	97.25	100.61	$0.00	9.44%
Avista	$30.62	$1.27	-	-	-	-	-	-	-	-	-	-	-	- -	-	
Black	$57.35	$1.56	1.67	1.79	1.91	2.04	2.19	2.33	2.48	2.62	2.77	2.91	100.88	103.78	$0.00	8.83%
Cleco	$50.30	$1.45	1.56	1.67	1.79	1.92	2.07	2.21	2.35	2.49	2.63	2.77	88.69	91.46	$0.00	9.08%
CMS	$29.09	$1.08	1.15	1.22	1.29	1.37	1.46	1.54	1.63	1.72	1.81	1.90	50.87	52.76	$0.00	9.73%
Great	$26.43	$0.92	0.97	1.02	1.07	1.12	1.18	1.24	1.30	1.37	1.44	1.50	45.88	47.39	$0.00	9.25%
Hawaiian	$24.72	$1.24	1.30	1.36	1.42	1.48	1.55	1.62	1.70	1.78	1.86	1.95	42.52	44.47	$0.00	10.63%
IDACORP	$55.22	$1.72	1.79	1.86	1.93	2.01	2.09	2.18	2.27	2.37	2.48	2.59	95.28	97.87	$0.00	8.65%
MGE	$38.63	$1.09	-	-	-	-	-	-	-	-	-	-	-	- -	-	
NorthWestei	$46.79	$1.60	1.72	1.84	1.98	2.12	2.28	2.44	2.59	2.75	2.90	3.05	82.58	85.63	$0.00	9.69%
OGE	$36.26	$0.90	0.95	1.01	1.06	1.12	1.19	1.25	1.32	1.39	1.46	1.53	63.30	64.83	$0.00	8.34%
Pinnacle	$55.05	$2.27	2.36	2.46	2.57	2.67	2.78	2.90	3.03	3.16	3.30	3.46	94.66	98.11	$0.00	9.64%
PNM	$26.91	$0.74	0.80	0.87	0.94	1.02	1.11	1.20	1.28	1.37	1.45	1.53	47.81	49.34	$0.00	9.16%
Portland	$32.32	$1.10	1.19	1.29	1.40	1.52	1.64	1.77	1.90	2.02	2.14	2.25	57.53	59.78	$0.00	9.93%
SCANA	$50.91	$2.03	2.12	2.22	2.33	2.43	2.55	2.66	2.79	2.92	3.05	3.20	87.90	91.10	$0.00	9.63%
TECO	$17.20	$0.88	0.92	0.97	1.02	1.07	1.12	1.18	1.23	1.29	1.35	1.42	29.67	31.09	$0.00	10.83%
UNS	$60.19	$1.92	-	-	-	-	-	-	-	-	-	-	-	- -	-	
Westar	$34.93	$1.40	1.45	1.49	1.54	1.59	1.65	1.70	1.77	1.84	1.92	2.00	59.72	61.72	$0.00	9.33%
Wisconsin	$45.93	$1.56	1.64	1.72	1.81	1.90	1.99	2.09	2.19	2.30	2.41	2.53	79.68	82.20	$0.00	9.13%
Average	$41.29	$1.44														9.45%
Median																9.38%

Sources and Notes:

[1] - [2]: ICNU Exhibit 210, Gorman

[2] - [7]: Calculated by applying the first stage growth rate to the annualized divdend in each year. Annualized dividend in year t = (Annualized dividend in year 0)*(1+ first stage growth rate)^(year t)

[8] - [12]: Calculated by applying the respective growth rate for each year to the forecasted dividend in the previous year. Annualized dividend in year t = (Annualized dividend in year t-1)*(estimated growth rate in year t)

[13]: Terminal Value calculated by applying the third stage growth rate (cell U5) to the forecasted dividend in year 10, and then treating the result as a perpetuity that is discounted to a single value in year 10 by dividing by the difference between the calculated discount rate and the third stage growth rate. Calculated as Terminal Value = (Forecasted Dividend In Year 10)*(1 + third stage growth rate) / (Calculated discount rate - third stage growth rate)

[14]: The sum of the terminal value [13] and the forecasted dividend in year 10 [14]

[15]: The difference in the 13-week average stock price [1] and the net present value of the forecasted dividends from year 1 to year 9 [3] - [11], in addition to the sum of the forecasted dividend in year 10 [12] plus the calculated terminal value [13]

[16]: The discount rate that sets the values in column [15] to zero

[17]: ICNU Exhibit 210, Gorman

[18]: Change this cell to change the third stage growth rate used in the model. 4.70% value from ICNU Exhibit 210, Gorman. 5.63% value represents average GDP growth rate from 1980 - 2013 and is taken from the GDP Growth Rate Tab

Equity Risk Premium - Treasury Bond (new ROEs)

Line	Year	Authorized Electric Returns [1]	Treasury Bond Yield [2]	Indicated Risk Premium (original) [2]	Indicated Risk Premium (revised)
1	1986	13.99%	7.80%	6.13%	6.19%
2	1987	12.98%	8.58%	4.41%	4.40%
3	1988	12.80%	8.96%	3.83%	3.84%
4	1989	12.97%	8.45%	4.52%	4.52%
5	1990	12.70%	8.61%	4.09%	4.09%
6	1991	12.54%	8.14%	4.41%	4.40%
7	1992	12.09%	7.67%	4.42%	4.42%
8	1993	11.46%	6.60%	4.81%	4.86%
9	1994	11.21%	7.37%	3.97%	3.84%
10	1995	11.58%	6.88%	4.67%	4.70%
11	1996	11.40%	6.70%	4.69%	4.70%
12	1997	11.33%	6.61%	4.79%	4.72%
13	1998	11.77%	5.58%	6.08%	6.19%
14	1999	10.72%	5.87%	4.90%	4.85%
15	2000	11.58%	5.94%	5.49%	5.64%
16	2001	11.07%	5.49%	5.60%	5.58%
17	2002	11.21%	5.43%	5.73%	5.78%
18	2003	10.96%	4.96%	6.01%	6.00%
19	2004	10.81%	5.05%	5.70%	5.76%
20	2005	10.51%	4.65%	5.89%	5.86%
21	2006	10.32%	4.99%	5.37%	5.33%
22	2007	10.30%	4.83%	5.53%	5.47%
23	2008	10.41%	4.28%	6.18%	6.13%
24	2009	10.52%	4.07%	6.41%	6.45%
25	2010	10.37%	4.25%	5.99%	6.12%
26	2011	10.31%	3.91%	6.16%	6.40%
27	2012	10.72%	2.92%	7.09%	7.80%
28	2013	10.02%	3.45%	6.34%	6.57%
29	2014	10.23%	3.68%	5.89%	6.55%
30	**10 year average**	**10.37%**	**4.10%**	**6.09%**	**6.27%**
31	**15 year average**	**10.62%**	**4.53%**	**5.96%**	**6.10%**
32	**20 year average**	**10.81%**	**4.98%**	**5.73%**	**5.83%**
33	**1986 - present average**	**11.34%**	**5.92%**	**5.35%**	**5.42%**

Sources and notes:

[1] Source: SNL, RRA rate case decisions. Years 1986 - 2012 from tab 'Past Rate Cases (1986 - 2012)', and years 2013-2014 from RRA Regulatory Focus, 'Major Rate Case Decisions', published January 15, 2014 and April 9, 2014

[2] ICNU Exhibit 212, Gorman

Equity Risk Premium - Utility Bond (new ROEs)

Line	Year	Authorized Electric Returns	Average "A" Rated Utility Bond Yield	Indicated Risk Premium (original)	Indicated Risk Premium (revised)
		[1]	[2]	[2]	
1	1986	13.99%	9.58%	4.35%	4.41%
2	1987	12.98%	10.10%	2.89%	2.88%
3	1988	12.80%	10.49%	2.30%	2.31%
4	1989	12.97%	9.77%	3.20%	3.20%
5	1990	12.70%	9.86%	2.84%	2.84%
6	1991	12.54%	9.36%	3.19%	3.18%
7	1992	12.09%	8.69%	3.40%	3.40%
8	1993	11.46%	7.59%	3.82%	3.87%
9	1994	11.21%	8.31%	3.03%	2.90%
10	1995	11.58%	7.89%	3.66%	3.69%
11	1996	11.40%	7.75%	3.64%	3.65%
12	1997	11.33%	7.60%	3.80%	3.73%
13	1998	11.77%	7.04%	4.62%	4.73%
14	1999	10.72%	7.62%	3.15%	3.10%
15	2000	11.58%	8.24%	3.19%	3.34%
16	2001	11.07%	7.76%	3.33%	3.31%
17	2002	11.21%	7.37%	3.79%	3.84%
18	2003	10.96%	6.58%	4.39%	4.38%
19	2004	10.81%	6.16%	4.59%	4.65%
20	2005	10.51%	5.65%	4.89%	4.86%
21	2006	10.32%	6.07%	4.29%	4.25%
22	2007	10.30%	6.07%	4.29%	4.23%
23	2008	10.41%	6.53%	3.93%	3.88%
24	2009	10.52%	6.04%	4.44%	4.48%
25	2010	10.37%	5.46%	4.78%	4.91%
26	2011	10.31%	5.04%	5.03%	5.27%
27	2012	10.72%	4.13%	5.88%	6.59%
28	2013	10.02%	4.48%	5.31%	5.54%
29	2014	10.23%	4.56%	5.01%	5.67%
30	**10 year average**	**10.37%**	**5.40%**	**4.79%**	**4.97%**
31	**15 year average**	**10.62%**	**6.01%**	**4.48%**	**4.61%**
32	**20 year average**	**10.81%**	**6.40%**	**4.30%**	**4.41%**
33	**1986 - present average**	**11.34%**	**7.30%**	**3.97%**	**4.04%**

Sources and notes:

[1] Source: SNL, RRA rate case decisions. Years 1986 - 2012 from tab 'Past Rate Cases (1986 - 2012)', and years 2013-2014 from RRA Regulatory Focus, 'Major Rate Case Decisions', published January 15, 2014 and April 9, 2014

[2] ICNU Exhibit 213, Gorman

UE 283 / PGE / 2100
Cody-Werner

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Marc Cody
Bruce Werner

July 16, 2014

Table of Contents

I. Introduction

Q. Please state your name and position.

A. My name is Marc Cody. I am a Senior Analyst in Pricing and Tariffs for PGE.

My name is Bruce Werner. I am an analyst in Pricing and Tariffs for PGE.

Q. Have you previously testified in this proceeding?

A. Yes, our qualifications are provided in PGE Exhibits 1300 and 1400.

Q. What is the purpose of this reply testimony?

A. We provide an update of the overall rate impacts and the impacts to the various rate schedules consistent with the testimony in PGE Exhibit 1700. We also address issues identified by OPUC Staff in three separate testimonies (Staff Exhibits 300, 700, and 800), and Kroger. Finally, we update the marginal cost of generation estimates in response to Staff testimony.

Q. Please summarize the updated projected Cost of Service rate impacts.

A. Table 1 below summarizes both the base rate impacts and the impacts with supplemental schedules included for the major rate schedules. The base rate impacts include the two new generation resources that PGE presumes will be on-line January 1, 2015. Included in the supplemental schedules are changes in Schedule 102 Regional Power Act Exchange Credit and Schedule 143 Spent Fuel Adjustment as well as estimated changes in Schedule 105 Regulatory Adjustments, Schedule 122 Renewable Resources Automatic Adjustment Clause, and Schedule 144 Capital Projects Adjustment. The rate impacts also include the stipulations reached to date in dockets UE 283, UE 286, and UM 1679. Table 1 below summarizes these estimated rate impacts.

Table 1
Estimated Cost of Service Rate Impacts

Schedule	Base Rates	With Supplementals
Schedule 7 Residential	3.9%	2.2%
Schedule 32 Small Nonresidential	2.7%	1.5%
Schedule 83 31-200 kW	3.6%	2.0%
Schedule 85 201-4,000 kW	3.7%	2.0%
Schedule 89 Over 4,000 kW	4.2%	2.4%
Schedule 90 100 MWa	4.2%	2.1%
COS Overall	3.8%	2.1%
COS & DA Overall	3.5%	1.8%

II. Staff 300

Q. What is the purpose of this portion of your testimony?

A. In this portion of our testimony we respond to Staff's recommendations regarding marginal customer costs, reactive power charges and two load forecasting issues.

Q. What are the customer marginal cost issues identified in Staff/300?

A. Staff proposes that PGE change the allocation of three components of customer marginal costs, correct a minor error in the billing calculations for lighting schedules, and separately identify the customer marginal costs for Schedules 89 and 90.

Customer Marginal Cost

Q. Do you agree with the Staff customer marginal cost recommendations?

A. Mostly, yes. We agree with the three components related to electronic billing, specialized billing, and printing and mailing and have incorporated these recommendations into the calculation of the unit marginal costs and updated rate impacts. The results of incorporating these recommendations into the customer marginal cost study are contained in the work papers accompanying this testimony. For one of the Staff recommendations, calculating the unit marginal costs separately for Schedules 89 and 90, we are still evaluating the recommendation and may have updates to this item in the future.

Line Extensions

Q. What does Staff propose regarding line extensions?

A. Staff proposes that PGE identify and send line extension refunds to eligible customers when applicable even if the customer has not requested a refund. Staff also proposes an accounting methodology for when line extension refunds do occur. Finally, Staff proposes that PGE inform customers of the maximum amount of potential line extension refund they may be able to receive from PGE at a future date should subsequent customers connect to a line extension for which they paid an amount in excess of the line extension allowance.

Q. Before discussing the Staff line extension proposals above, do you wish to point out any erroneous and/or misleading statements made by Staff?

A. Yes, there are five instances where Staff makes unsupported statements that appear to stem from either misunderstanding of line extensions or PGE responses to their data requests:

1) Page 42, lines19-20: Staff claims that the OPUC regularly receives customer complaints regarding line extensions.

2) Page 42, lines 21-23: Staff claims that "PGE socializes the cost of line extensions, which results in higher rates for all customers."

3) Page 43, lines 6-11: Staff claims that the Company socializes the cost of refunds and that the cost of refunds is not included in the cost quotes given to subsequent customers.

4) Page 43 lines 12-19: Staff claims that when the Company identifies that a customer is due a refund, the Company does not provide the refund.

5) Page 45, lines 10-18: Staff claims that in their review of work orders, the line extension quote was higher than the "actual cost" and that PGE's estimates overstate costs which indicate that the Company may be over-collecting its costs.

Q. Please show why Staff's statement that the OPUC regularly receives customer complaints regarding line extensions is exaggerated.

A. PGE has received two OPUC complaints regarding line extensions in the three year period ending 2013. In two of the years there were no line extension-related complaints. There have been numerous line extensions made during this time period. PGE provided the list of historical complaints in PGE's response to OPUC Data Request No. 199 provided as PGE

Exhibit 2101. This response does not support Staff's assertion that the OPUC receives regular complaints regarding line extensions.

Q. Please address Staff's claim that because PGE "socializes" a portion or all of a line extension cost, other customers experience higher rates.

A. Consistent with its tariff, PGE does "socialize" line extension costs up to the amount of the line extension allowance as specified in its Commission-approved Schedule 300. Line extension costs up to the amount of the line extension allowance (LEA) are posted to a particular plant in service account and become part of PGE's regulated rate base. Amounts exceeding the LEA are paid for by the customer. However, contrary to what Staff seems to imply, PGE does not, and cannot, automatically adjust other customer rates each time rate base goes up (or down), but rather PGE sets rates based on a future test period that will include the historical line extension costs not directly paid for by customers. In short, PGE experiences regulatory lag on the plant additions resulting from line extensions. Furthermore, individual customers provide additional revenue and billing determinants over which the total of PGE's fixed costs is spread in a future forecasted test period. It is overly simplistic to make a wholesale statement that providing line extension allowances results in higher rates for all customers.

Q. Please demonstrate why Staff's statement that PGE does not track the impacts of refunds on rate base is incorrect and misleading.

A. We asked the appropriate distribution personnel how they treat line extension refunds when a second customer connects to a line extension previously paid for, in part, by a prior customer. The response is as follows:

1) Calculate the current costs of all shared facilities and divide in half.

2) Refund this dollar amount to the original customer.

3) Add the cost of the refund to the second customer's line extension costs as well as the costs of any other additional facilities.

4) Apply the line extension allowance to the second customer's line extension costs.

Q. Please address Staff's claim that PGE does not provide refunds to customers even though PGE has identified that the customer is due a refund.

A. Staff attempts to support their claim citing PGE's responses to OPUC Data Requests Nos. 197 and 402. However, these responses do not support Staff's assertion. The intent of the response to OPUC Data Request No. 197 is to specify that line extension refunds are provided in less than 10% of the cases where a customer may be potentially eligible for a refund for a prior line extension. The reason for this low incidence is simple: according to our distribution personnel, it is because generally there is a low incidence of a subsequent customer connecting to the first customer's line extension within the five-year period specified in PGE's tariff. Furthermore, in PGE Response to OPUC Data Request No. 402, PGE specified the following:

> PGE field personnel attempt to determine if a pre-existing line extension is relatively new when they receive a request for new service from a customer. If PGE can verify that the prior line extension is less than five years old, it attempts to notify the original customer or applicant for whom the line extension was constructed.

Q. Please demonstrate why Staff's statement that PGE's job quotes are higher than actual costs is incorrect and misleading.

A. Staff's misunderstanding appears to stem from PGE's response to OPUC Data Request No. 397. In the voluminous confidential attachment to this response, PGE provided numerous cost estimates for line extension jobs. The job cost estimates had two columns, one containing the estimate for the line extension job, the other containing a field called "Actual." The "Actual" column under PGE's prior accounting system would refresh for actual job costs if one wished to check the actual costs of a job after completion. When PGE changed accounting systems and began using PowerPlant in 2011, the column titled "Actual" did not retain the ability to accurately represent actual costs, but rather printed information that has no value or meaning.

Q. Could you please provide some examples of what you discuss above?

A. Yes, we provide two examples in PGE Exhibit 2102. The names of the customers have been redacted. Page 1 of this exhibit presents a job for a 367 multi-family development with two commercial buildings. The cost and man-hours that appear under the "Actual" field are both zero. Clearly, this is nonsense. Page 2 of PGE Exhibit 2102 is for a job requiring among other things, the installation of two transformers. The "Actual" shows a total cost of $237.63 and two man-hours. Again, this is clearly nonsensical and should have demonstrated to Staff that the "Actual" field could not be relied upon.

Q. Has Staff claimed that PGE is not following the line extension language in its tariff?

A. No.

Q. Please evaluate Staff's proposals regarding the refunding of eligible customers line extension costs.

A. As specified in PGE Response to OPUC Data Request No. 402, PGE does attempt to identify potential line extension refunds and provide these refunds to customers. While currently PGE does not maintain a database to identify all potential line extension refunds, we have asked distribution personnel to investigate incorporating this type of database. Distribution personnel have informed us that when the new work management system, Maximo, comes on line in October 2014, they will work to incorporate the logic that will allow for electronic tracking of potential line extension refunds.

Q. Please evaluate Staff's proposal regarding the accounting of refunds.

A. PGE believes that what Staff proposes is reasonable and captures the manner in which PGE currently handles refunds.

Q. Is PGE willing to inform customers of the maximum amount of refund to which they may be entitled at the time customers and PGE sign a line extension agreement?

A. Yes. PGE already does so in its line extension agreement. PGE could slightly alter the agreement so that it more clearly shows the amount of potential future refund should a subsequent customer or customers connect to the line extension.

Reactive Power

Q. What does Staff propose regarding the charges for reactive power?

A. Staff recommends that the Commission direct PGE to study the costs of reactive power to evaluate if PGE's current reactive demand charge reflects the costs of correcting for reactive power. Staff further states that if there is some sort of "significant cost shift due to reactive power, then the Company should incorporate reactive power costs into the marginal cost study." Staff further recommends that the study of these costs be prepared and acted upon by January 1, 2016.

Q. Have the parties to this proceeding reached an agreement on this issue?

A. Yes. The parties to this proceeding have reached an agreement that in its next general rate case, PGE will evaluate if the current charges for reactive demand are appropriate.

III. Staff 700

Q. What is the purpose of this portion of your testimony?

A. In this portion of our testimony we respond to Staff's recommendations regarding alternative rate spread through the Customer Impact Offset (CIO), the energy pricing of large nonresidential customers, and residential customer charges.

Q. What does Staff propose regarding the CIO?

A. Because Staff proposes that wind generation be included in the marginal cost of generation, they propose to adjust the CIO for each schedule contributing to the CIO as opposed to a uniform charge to partially offset the price increases to certain schedules. Staff also cites a desire to have the percentage impacts for each rate schedule more closely approximate the overall percentage impacts as a reason for adjusting the CIO. Staff further proposes to change the ceiling on price increases for the irrigation Schedules 47 and 49 to the greater of 7% or three times the overall cost-of-service (COS) increase. PGE's proposal was to place a ceiling of 12% on the price increase for the irrigation schedules plus the amount of increase related to the two new generation plants, Tucannon River Wind Farm and Port Westward 2.

Q. Do you agree with Staff's proposals?

A. Partially. We agree that in certain circumstances it may be desirable to bring the rate impacts closer to the overall average price increase. We therefore propose to retain the uniform CIO contributions for applicable rate schedules 7, 32, 38, 83, 85, 89, and 90, but to limit the rate impacts of these CIO contributors such that they contribute on a uniform basis only if their percentage rate increase is no more than 1.5% greater than the overall COS average. If the rate impact for these individual rate schedules exceeds 1.5% more than the overall average, then we propose that they make no CIO contribution.

Regarding Staff's proposal for the irrigation schedules, we propose that these schedules receive the greater of a 12% increase or three times the overall revenue requirement increase. We believe that this proposal comes closer to Staff's stated goal of reducing the CIO subsidy to the irrigation schedules.

Q. What does Staff propose regarding the pricing of generation-related charges for large nonresidential customers?

A. Staff proposes that PGE implement generation demand charges during the months of January, July, August, and December for the large nonresidential rate Schedules 83, 85, 89, and 90. More specifically, Staff proposes that these generation demand charges be more akin to coincident peak demand charges with PGE providing a 24-hour notice to customers during four days of the months specified above. This 24-hour notice would inform customers that the following day may be a day during which a coincident peak may occur. The applicable peak billing determinant for each customer would be their peak demand that occurred on the highest peak day of the specified four days of the month. This billing determinant would fall within the currently defined on-peak periods of 6:00 AM to 10:00 PM, Monday through Saturday.

Staff also proposes that PGE adopt a three-period peak energy rate design for generation energy charges not recovered by their generation demand charge. These three peak periods would correspond to the three peak periods defined for PGE's voluntary time-of-use portfolio option applicable to Schedule 7 and 32. Finally, acknowledging that their proposals will be difficult to implement in PGE's current billing system, Staff proposes that PGE should be instructed to sponsor a workshop that fosters discussion of their recommendations among PGE and customers.

Q. Does Staff acknowledge that implementing their proposals would be costly and time consuming?

A. Yes. Staff acknowledges that PGE's billing system does not currently have the capability to implement their demand charge proposals. Staff also states that for the sake of economic efficiency, PGE should provide for the capability to implement their demand charge proposals within PGE's new billing system which is scheduled to be on-line in 2017 rather than try to implement their proposed changes into a soon-to-be obsolete billing system.

Q. Given Staff's acknowledgement of the lack of desirability of changing PGE's current billing system, do they propose changes to large nonresidential customer rate design for the 2015 test-period?

A. Yes. Staff proposes that PGE implement their three peak periods for the energy charge with larger price differentials than currently exist for the two current peak periods. In the alternative, Staff proposes that the current peak period structure be retained, but that the on- and off-peak price differentials be increased from the current one cent per kilowatt-hour (kWh) to two cents per kWh.

Q. Do you agree with this Staff proposal?

A. Yes, partially. We agree that a better cost-based pricing signal would be achieved by increasing the current on- and off-peak price differentials for Schedules 83, 85, 89, and 90. However, we propose a more moderate, gradual approach: raising the differential to 1.5 cents per kWh instead of the two cents per kWh recommended by Staff. With respect to the three-peak period proposal, we point out that this proposal has the same issues as the generation demand charge proposal, namely that PGE does not currently have the capability to implement the proposal within its current billing system in a timely, economical manner.

Q. Do you agree that PGE should hold workshops regarding the implementation of the Staff proposals?

A. Yes. PGE agrees that a workshop to discuss the Staff proposals and the proposals of other parties including PGE would be beneficial for all parties. Among the issues to discuss at the workshop should be the applicability of the various proposals to direct access customers; potential impact to the direct access programs if any; potential revenue volatility; cycle billing; and the appropriate demand billing determinants for future rate-making.

Q. What does Staff propose regarding the Schedule 7 Residential customer charge?

A. Staff proposes that the Schedule 7 customer charge remain at $10.00 per month, as opposed to the $11.00 per month customer charge proposed by PGE in its direct testimony.

Q. What is the basis for Staff's proposal?

A. Staff cites two reasons: 1) Staff states that PGE's proposal to raise the customer charge by 10% when the overall proposed price increase is less than 5% "may well stretch things from a customer acceptance/credibility point of view." 2) Staff claims that the summed marginal cost of "universally accepted" customer cost/basic-charge components supports a figure less than $10.00 per month.

Q. Do you agree with Staff's claim that a 10% increase in the residential customer charge may be unacceptable?

A. No. The Schedule 7 initial proposed base rate change with inclusion of the two new generation stations was approximately 6.8%. A 10% increase in the customer charge does not seem egregious.

Q. Do you agree with Staff's second reason for proposing to keep the residential customer charge at $10.00?

A. No. Staff's "universally accepted" methodology looks solely at the distribution and billing marginal cost components before they are grossed up for embedded cost revenue requirements. We see no reason for Staff to exclude the marginal costs associated with the functional categories Metering and Other Consumer, not to mention the uncollectible accounts allocated to Schedule 7. These categories are contained in the normal customer-related FERC accounts (Accounts 901-917).

Q. Notwithstanding your comments above, do you still propose an increase in the Schedule 7 Basic Charge?

A. No, we now propose to accept Staff's proposal to keep the Schedule 7 customer charge at $10.00 per month. We intend to pursue the appropriate level of residential customer charge in a future docket.

IV. Staff 800

Q. What is the purpose of this portion of your testimony?

A. In this portion of our testimony we respond to Staff's proposal regarding the calculation of the marginal cost of generation.

Q. How does Staff propose to calculate the marginal cost of generation?

A. Staff proposes to include the cost of wind resources in its marginal cost of generation. More specifically, Staff uses the Renewable Portfolio Standard (RPS) percentages for the period 2015-2034 to calculate a weighted marginal cost of generation using PGE's estimate of the marginal cost of thermal resources and Staff's estimate of the marginal costs of wind resources.

Q. Do you oppose including wind in the marginal cost of generation?

A. No, as Staff correctly points out, PGE has proposed including wind resources in two prior general rate cases. PGE did not include wind in this docket because in last year's rate case, UE 262, the parties stipulated to a marginal cost of generation that excluded wind.

Q. Do you agree with the manner in which Staff has included wind to estimate the marginal cost of generation?

A. No. The most prominent point of disagreement is that Staff inappropriately includes the additional cost of flexible capacity resources needed to remedy the intermittent nature of wind generation as an energy cost rather than as a capacity cost.

Q. What is Staff's stated justification for classifying the additional or incremental capacity costs of flexible capacity resources as energy.

A. Staff states the following on page 3 of Staff /800:

> Staff's position is that if PGE is building variable generating resources as a direct result of building wind resources then any capital costs beyond that of

> a SCCT must be a direct result of having wind resources. Given that Staff views wind as an energy-only resource, the additional $/kW cost of the variable generating capacity resource beyond that of a SCCT should be assigned as an energy cost only relating to supplying wind because it does not increase the peak generating capacity of PGE beyond that of a basic SCCT.

In addition, Staff states the following on page 5 of Staff/800:

> Staff proposes that the portion of the flexible thermal resources that exceeds the SCCT $/kW costs, dedicated as a reserve to offset wind variability and to maintain system reliability, should be identified as part of the marginal energy cost and not as part of the capacity cost component of the marginal generation cost estimation. Staff has developed a new methodology that improves upon the Company's approach to including wind costs in marginal generation cost analysis.

Q. Why do you disagree with Staff's statements?

A. Wind is an intermittent resource that requires a more flexible type of capacity to remedy the nature of its intermittency. This flexible capacity is more expensive than a typical or basic SCCT. We have no issue with Staff classifying the majority of wind plant costs such as capital carrying costs, land rents, fixed O&M, and production tax credits as marginal energy costs. However, for Staff to claim that the more expensive flexible capacity increment associated with wind is an energy cost simply because they have classified the wind resource itself as energy makes no sense. In short, Staff's argument is simply an assertion of opinion without justification. It is true that a flexible capacity resource does not provide more nameplate capacity than a less flexible capacity resource; it is simply more expensive because of the need for the rapid-start times and ramping capabilities due to the intermittent nature of wind generation. This more expensive flexible capacity is appropriately classified as a capacity cost.

Q. Please summarize Staff's "new methodology".

A. 1) Use PGE's estimated marginal thermal capacity and energy costs before consideration of the RPS.

2) Calculate a weighted average of thermal and wind marginal energy costs based on RPS requirements by year.

3) Calculate the marginal cost of wind energy by using the "direct wind energy cost" and the incremental cost of a flexible thermal resource. This incremental cost is defined as the cost per kW differential between the flexible capacity resource and a less flexible capacity resource. Treat this incremental cost difference as an energy cost.

4) Assume that the flexible capacity resource has a nameplate capacity of 220 MW and that it can integrate all of PGE's wind resources, current and proposed, of over 700 MW of nameplate capacity.

5) Calculate the incremental costs of the flexible capacity resource on a $/kW-year basis times the 220 MW nameplate capacity.

6) Divide the total cost calculated in 5) above by PGE's projected 2015 wind generation in megawatt-hours (MWh).

7) Calculate wind energy costs as the sum of capital carrying costs, fixed O&M costs, land rents, production tax credits, ancillary services, and integration costs of $3.63/MWh as specified in PGE's Integrated Resource Plan (IRP).

Q. What strikes you as problematic in the Staff analysis?

A. Besides the important aforementioned issue of counting capacity costs as energy costs there are several issues:

1) The presumption that 220 MW of flexible capacity can support more than 700 MW of nameplate wind generation is unsupported.

2) The integration costs of $3.63 and any ancillary service costs used are more appropriately classified as capacity costs instead of energy costs.

3) The Staff analysis includes neither fixed gas transportation nor the fixed costs of gas storage, both of which are capacity costs. In the case of Port Westward 2, storage is used rather than additional pipeline capacity. PGE specified this in our response to OPUC Data Request No. 300.

Q. It appears that with respect to how to treat flexible capacity resources PGE and Staff are at a sort of impasse. Neither PGE nor Staff can accurately quantify the amount of flexible capacity needed to integrate a particular quantity of wind generation. Can you suggest a manner to calculate the marginal energy cost of wind and the capacity costs necessary to integrate wind generation that does not involve a new flexible capacity resource?

A. Yes. Since it is difficult to precisely determine the amount of flexible capacity resources needed to integrate a megawatt of wind, we suggest a generation marginal cost analysis that does not include a new flexible capacity resource, but rather one that relies upon currently available integration services in combination with a more standard peaking resource such as presented in PGE's opening testimony.

Q. Have you performed such an analysis?

A. Yes. PGE Exhibit 2103 contains the summary detail of the analysis.

Q. Please describe how you performed this analysis.

A. We first re-estimated the capacity and energy costs of the thermal resources with the following updates:

1) Consistent with PGE's recent UM 1610 filing, extend the economic life of the frame F thermal peaking unit from 20 years to 30 years. This reduces the per unit capacity costs.

2) Extend the economic life of the baseload thermal resource from 30 years to 35 years consistent with the 2013 IRP assumptions.

3) Update the long-term gas price forecast for more current information.

4) Include the wind generation costs consistent with the UM 1610 parameters and the UE 286 stipulated capacity factor of 38.2%.

5) Include the Variable Energy Resource Balancing Services (VERBS) from the Bonneville Power Administration (BPA) as an additional capacity cost for wind. This is an objective, verifiable cost that PGE and others currently incur to integrate wind resources.

6) Include an estimate of fixed gas transportation for the frame F peaker as an additional capacity cost applicable to the portion of marginal costs attributable to wind generation.

Q. What is VERBS and how does BPA charge customers for its VERBS?

A. VERBS is applicable to all large wind and solar generating facilities in BPA's control area. The services provided are regulating <u>reserves</u>, following <u>reserves</u>, and imbalance <u>reserves</u>. BPA charges customers on a $/kW-month basis for VERBS based on the generators nameplate capacity.

Q. How are these reserves provided?

A. Generally, reserves are provided from flexible <u>capacity</u> resources such as hydro.

Q. Why do you include fixed gas transportation as a capacity resource for the wind portion of the marginal generation costs?

A. We include fixed gas transportation because VERBS provides for the within-hour fluctuations of wind resources, not for the hour-to-hour fluctuations. Hence a peaking resource would need a reliable supply of on-demand gas to compensate for the large hour-to-hour fluctuations associated with wind generation. Contracting for fixed gas transportation fulfills this need for reliable gas supply.

Q. Has Staff previously agreed that fixed gas transportation is an appropriate capacity cost?

A. Yes, in UE 215, Staff supported inclusion of fixed gas transportation as an appropriate generation capacity cost. In fact, Staff supported fixed gas transportation not only for the portion of marginal generation costs attributed to wind, but also the portion attributable to thermal resources. Specifically, Staff's stated the following: "I accept the estimated gas transport cost and 12% reserve additions…….." (UE 215 Staff/1000-Ordonez/7, line 9.)

Q. In percentage terms, what are the differences in capacity and energy values from your direct testimony?

A. The capacity costs of $98.15 are 2.0% lower and the energy costs of $49.12 are 1.5% lower.

Q. What do you recommend to the Commission regarding marginal generation costs?

A. We recommend that the Commission adopt the updated marginal generation costs presented in this testimony because PGE's methodology allows for the inclusion of wind generation resources in the generation marginal cost study with capacity and energy appropriately classified.

V. Kroger

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of our testimony is to respond to the testimony of Fred Meyer Stores, a division of the Kroger Co. henceforth referred to as Kroger. Kroger's testimony identifies as an issue the higher percentage increase for primary voltage Schedule 85 customers' demand and facility capacity charges than for secondary voltage Schedule 85 customers.

Q. What does Kroger recommend regarding this issue?

A. Kroger recommends that the current absolute price differentials for demand and facility capacity charges between secondary and primary voltage customers be maintained.

Q. In your opinion, is Kroger's recommendation reasonable?

A. Yes. Given that primary voltage Schedule 85 customers are expected to experience a higher percentage increase than secondary voltage customers, Kroger's recommendation provides for a more stable within-class rate impact than would otherwise occur.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2101	PGE Response to OPUC Data Request No. 199
2102C	Line Extension Estimate Examples
2103	Marginal Generation Costs

March 25, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 199
Dated March 12, 2014

Request:

Please provide all customer complaints related to Line Extensions or Rule I received by PGE from January 1, 2009 through current.

Response:

PGE's Customer Complaint database covering the period of January 1, 2009 to current shows 11 associated complaint cases regarding Line Extensions. The years in which these complaint cases were received are as follows:

2009 - Four associated cases
2010 - Four associated cases, 1 inquiry
2011 - Zero associated cases
2012 - Zero associated cases
2013 - Two associated cases

Attachment 199-A provides each of the above-mentioned cases or inquiry as recorded, with no At-Fault violation assessed in any case.

Attachment 199-A is confidential and subject to Protective Order No. 14-043.

Exhibit 2102C

Confidential

Year	Thermal Capacity SCCT $/kW-year	SCCT Fixed Gas Transport $/kW-year	VERBS $/kW-year	Wind Capacity w VERBS $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Weighted Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2015	87.10	39.83	14.68	141.60	49.51	47.56	15.00%	95.27	49.22
2016	88.78	40.60	14.96	144.34	50.47	48.48	15.00%	97.11	50.17
2017	90.49	41.38	15.25	147.12	51.44	49.41	15.00%	98.98	51.14
2018	92.24	42.18	15.54	149.96	52.44	50.36	15.00%	100.90	52.12
2019	94.02	43.00	15.84	152.86	53.45	51.34	15.00%	102.84	53.13
2020	95.83	43.83	16.15	155.81	54.48	52.33	20.00%	107.83	54.05
2021	97.68	44.67	16.46	158.81	55.53	53.34	20.00%	109.91	55.09
2022	99.57	45.53	16.78	161.88	56.60	54.37	20.00%	112.03	56.16
2023	101.49	46.41	17.10	165.00	57.69	55.42	20.00%	114.19	57.24
2024	103.45	47.31	17.43	168.19	58.81	56.49	20.00%	116.39	58.34
2025	105.44	48.22	17.77	171.43	59.94	57.58	25.00%	121.94	59.35
2026	107.48	49.15	18.11	174.74	61.10	58.69	25.00%	124.29	60.50
2027	109.55	50.10	18.46	178.12	62.28	59.82	25.00%	126.69	61.66
2028	111.67	51.07	18.82	181.55	63.48	60.97	25.00%	129.14	62.85
2029	113.82	52.05	19.18	185.06	64.71	62.15	25.00%	131.63	64.07
2030	116.02	53.06	19.55	188.63	65.96	63.35	25.00%	134.17	65.30
2031	118.26	54.08	19.93	192.27	67.23	64.57	25.00%	136.76	66.56
2032	120.54	55.13	20.31	195.98	68.53	65.82	25.00%	139.40	67.85
2033	122.87	56.19	20.71	199.76	69.85	67.09	25.00%	142.09	69.16
2034	125.24	57.27	21.11	203.62	71.20	68.38	25.00%	144.83	70.49
Real Levelized	$87.10	$39.83	$14.68	$141.60	$49.51	$47.56		$98.15	$49.12
NPV	$1,119	$512	$189	$1,820	$636	$611		$1,262	$631
Nominal Levelized	$101.06	$46.22	$17.03	$164.30	$57.45	$55.18		$113.89	$56.99
Real Levelized	$87.10	$39.83	$14.68	$141.60	$49.51	$47.56		$98.15	$49.12