Portland General Electric
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June 20, 2018

Via Email /FedEx
puc.filingcenter@state.or.us

Oregon Public Utility Commission
Attention: Filing Center
PO Box 1088
Salem, OR 97308-1088

Re: UE___ – 2017 Annual Power Cost Variance Mechanism

Attention Filing Center:

Enclosed for filing in the above-captioned docket please find the following:

- **Alex Tooman and Greg Batzler (PGE/100-102, PGE/104)**
- **Work Papers (non-confidential portions only)**
- **Portland General Electric Company's Motion for Protective Order (with Proposed Protective Order)**

Exhibit **PGE/103C** is confidential and will be submitted, along with the confidential work papers, after entry of a Protective Order.

These documents are being filed electronically.

Thank you in advance for your assistance

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

SB:np

Enclosures

Table of Contents

I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Alex Tooman. I am a senior regulatory consultant at PGE.

My name is Greg Batzler. I am a senior regulatory analyst at PGE.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two-fold. First, we describe the 2017 Power Cost Variance (PCV), including base and actual power costs. Second, we describe how we determined the deferred amount for power costs using the Power Cost Adjustment Mechanism (PCAM) authorized by the Public Utility Commission of Oregon (OPUC or Commission) in Order No. 07-015 (Docket UE 180) and established in PGE Schedule 126. In summary, because the Annual Variance of $15 million (i.e., actual power costs are greater than forecasted power costs) is entirely within the power cost deadbands, the 2017 PCV and deferral are zero.[1]

Q. Please summarize the process used in the PCAM.

A. The first step in the process compares PGE's actual unit Net Variable Power Costs (NVPC) with our base unit NVPC and then multiplies the difference by actual load to determine an Annual Variance. We then apply asymmetrical power cost deadbands to the Annual Variance followed by a 90-10 percent sharing between customers and shareholders to develop the PCV. After this, we apply a symmetrical Return on Equity (ROE) deadband to an earnings review to determine how much, if any, of the final PCV should be collected from or refunded to customers (PGE Exhibit 101 provides a summary of the PCV

[1] In our testimony, any negative or credit amounts are signified as ($_____).

calculation). If there is a collection from or refund to customers, this amount is then posted to PGE's PCV account where it will accrue interest at PGE's authorized rate of return, until the Commission approves amortization. Finally, if there is a collection from or refund to customers, PGE would amortize the PCV balance through Schedule 126, which is an Automatic Adjustment Clause as defined in ORS 757.210.

Q. Are there Minimum Filing Requirements (MFRs) associated with the PCAM?

A. Yes. In PGE's 2007 PCAM (Docket No. UE 201), parties agreed to MFRs for future PCAMs. The MFRs specify that work papers to PGE's PCAM filing should include the following:

- Monthly transaction-level detail by ledger number that is used to summarize actual power costs as provided in PGE Exhibit 103C; and
- Detail regarding PGE's out-of-period adjustments.

As specified, confidential work papers to this filing include the required documentation.

Q. How is your testimony organized?

A. We begin by describing in greater detail how PGE calculated the PCV as determined by the Annual Variance and the power cost deadband. We then briefly describe PGE's PCAM earnings review although it is not applicable for 2017. The last section contains our qualifications.

II. Calculation of PCV

A. Base Power Costs

Q. What is the first step in calculating the PCV?

A. The first step is to identify PGE's baseline NVPC, which are based on the final 2017 power cost forecast that PGE calculated in UE 308, using our power cost forecasting model, MONET.[2] The MONET result establishes the unadjusted baseline NVPC of approximately $382.9 million for 2017.

Q. Did you apply any adjustments to derive these base costs?

A. Yes. From the unadjusted baseline NVPC, we reduced power costs by another $2.5 million to recognize steam sales from our Coyote Springs plant (as forecasted in UE 294). We applied this adjustment as directed by the Commission in Order No. 07-015 to achieve adjusted baseline power costs.

Q. Did you apply an adjustment for Ancillary Service Revenues as also directed by Commission in Order No. 07-015?

A. No. Because this revenue was incorporated directly into the MONET baseline power costs as filed in UE 308, there is no Ancillary Service adjustment necessary to calculate the 2017 PCV.

Q. Did you apply an adjustment related to direct access and variable price option load?

A. Yes. PGE reduced power costs related to the additional 30.6 MWa of 2017 direct access and variable price option load that had not been identified at the time the final MONET

[2] PGE has described the MONET model in the last nine general rate proceedings (i.e., UE 115, UE 180, UE 188, UE 197, UE 215, UE 262, UE 283, UE 294, and UE 319) as well as previous RVM filings (Resource Valuation Mechanism – UE 139, UE 149, UE 161, and UE 172) and AUT filings (Annual Update Tariff – UE 192, UE 208, UE 228, UE 250, and UE 308). Consequently, we incorporate those descriptions by reference.

forecast was prepared in November 2016. This reduced base power costs by another $7.0 million and, of course, it also reduced the base loads used to determine unit NVPC.

Q. Did you apply any other adjustments to the MONET output?

A. Yes. Similar to the treatment of steam sales, we increased power costs by $1.3 million, from the unadjusted baseline NVPC, to recognize PGE's forecast of wind availability charges in UE 294. As wind availability damages/bonuses are included as an adjustment to actuals, to provide a comparable basis, we also include the UE 294 forecast as an adjustment to baseline NVPC.

Q. What was the final baseline NVPC estimate?

A. After the adjustments described above, baseline NVPC for 2017 were approximately $374.6 million.

B. Actual Power Costs

Q. What is the next step in calculating the PCV?

A. The next step is to calculate PGE's actual NVPC for 2017. We begin this step by identifying PGE's variable power costs as charged to the following FERC accounts: 501, 547, 555, and 565. We then include the amount of sales for resale, as charged to FERC 447. For 2017, this net amount is approximately $486.9 million. To this amount, we apply a number of adjustments as listed in Table 1, and described below.

Table 1
Adjustments to Actual 2017 Power Costs
($000)

Actual NVPC per financial statements (see Exhibit 103C)		$486,891
Items to Exclude:		
FAS 133/71, mark-to-market deferrals	subtract	0
Credit reserve activity	subtract	76
Out of period items	subtract	0
Direct access deferral amortization	subtract	758
Green power costs billed directly to customers	subtract	12,417
Solar Payment Option - Sch205/206 avoided costs	subtract	874
Automated demand response pilot	subtract	895
2017 amortization of 2015 net wheeling credit	subtract	(660)
Carty Lateral Capital Lease Reclassification	subtract	(4,072)
Items to Include:		
Coyote steam sales	add	(1,892)
Gas resale margin	add	(5,551)
Transmission resale revenues	add	(8,110)
Wind availability (credit)/charge	add	524
Energy revenues for variable price option customers	add	(3,821
Chemical costs in O&M	add	5,511
Production Tax Credits in Taxes	add	(63,271)
Adjusted Actual NVPC*		$399,990

*May not sum due to rounding

Q. Please describe the items PGE excluded from its actual NVPC.

A. PGE excluded the following costs from actual NVPC:

- A charge of approximately $76,000 for reserve activity related to non-retail customers during the PCAM period.
- A charge of approximately $0.8 million for the direct access deferral amortization. This charge was recorded to FERC account 447 and represents amortization of the deferral on the net gain on power costs associated with the large non-residential load shift true up. This charge is included in a supplemental schedule.
- $12.4 million for green power expenses that are billed directly to customers through Schedules 7, 32, and 54. Consequently, they should not be included when calculating the PCV.

- A charge of approximately $0.9 million for the avoided costs associated with PGE's Solar Payment Option (SPO – Schedules 215, 216, and 217).[3] To eliminate double counting, this entry removes the increase to power costs that is associated with the avoided cost benefit, which is applied to the SPO deferral.
- A charge of approximately $0.9 million related to PGE's automated demand response pilot (ADR). Because ADR costs are collected through Schedule 135, we exclude them here to avoid double counting.
- A credit of approximately ($0.7 million) to reverse the 2017 amortized portion of PGE's 2015 net payment[4] for acquiring BPA wheeling rights from two, third parties in 2015.
- A credit of approximately ($4.1 million) to reflect the reclassification of the Carty Lateral Capital Lease from operation and maintenance (O&M) costs to power costs, consistent with FERC accounting rules.

Q. What adjustments did PGE make to include items in actual NVPC?

A. PGE included the following items in actual NVPC:

- A credit of approximately ($1.9 million) for actual steam sale revenues from the Coyote Springs 1 plant.
- A credit of approximately ($5.6 million) for gas resale margin.
- A credit of approximately ($8.1 million) for transmission resale revenues, net of lost transmission revenues from direct access customers.

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[3] Previously known as the Solar Feed-in Tariff, Schedules 205 and 206.
[4] Gross payment less fees to BPA to defer the rights for later use.

- A charge of approximately $0.5 million for the wind availability adjustment. This charge effectively offsets lower purchased power costs due to PGE's wind plants having a higher availability factor than contracted.
- A credit of approximately ($3.8 million) for energy revenues from variable price option customers.
- A charge of approximately $5.5 million for pollution control chemicals. In summary, these chemical costs are forecasted in the AUT, but recorded as operations and maintenance costs because the chemicals are injected after the fuel burn. Consequently, we add them to the PCAM to accurately match the components of actual and baseline power costs.
- A credit of approximately ($63.3 million) for production tax credits (PTCs). As PTCs are now forecast in NVPC consistent with the provisions of Oregon Senate Bill 1547, Section 18b,[5] we add them to the PCAM to accurately match the components of actual and baseline power costs.

Q. Why did you include a credit for transmission resale revenues in actual power costs?

A. We did so because it is similar to gas and oil resales. In all these categories, the associated fuel and wheeling expense is in power costs, but the resale revenue is recorded in Other Revenue. To correctly reflect the net power costs associated with these categories, we adjust power costs to reflect the resale revenue.

Q. Are sales of ancillary services included in actual NVPC?

A. No. In 2017, there was no opportunity for these sales. Consequently, there was no revenue from the sales of ancillary services in FERC account 447.

[5] Senate Bill 1547 was signed into law by the governor on March 11, 2016.

Q. What is the final actual NVPC?

A. After all the adjustments described above, the final actual NVPC total is approximately $400.0 million.

C. Unit Power Costs and Annual Variance

Q. What is the next step in calculating the PCV?

A. The next step is to unitize the base and actual NVPC so as to calculate a unit NVPC variance. To accomplish this, we divide base NVPC and actual NVPC by base loads and actual loads, respectively. In both cases, we use retail cost of service loads. The unit NVPC variance is calculated by subtracting base unit NVPC from actual unit NVPC. We perform this step to eliminate the power cost variance that would arise from changes in load.

Q. What is the unit NVPC variance and how do you calculate the Annual Variance?

A. Although PGE Exhibit 101 lists the PCV on a monthly basis, the unit NVPC variance for purposes of the PCAM is based on annual amounts. For 2017, the unit NVPC variance is approximately $0.86 per MWh (i.e., actual unit NVPC is larger than base unit NVPC). We then calculate the Annual Variance by multiplying the unit NVPC variance times actual load. This produces an Annual Variance of approximately $15.0 million.

D. PCV

Q. What is the final step in calculating the PCV?

A. The final step is to apply the deadband and sharing percentages, if applicable, to the Annual Variance. Because we focus on the earnings review and return on equity (ROE) deadband in the next section, we only discuss the power cost deadband here.

Q. What is the power cost deadband?

A. Beginning January 1, 2011, the power cost deadband is calculated based on Commission Order No. 10-478 (Appendix D, page 3 of 11), which specifies the following:

- $30 million for a positive Annual Variance; and
- ($15 million) for a negative Annual Variance.

This update is reflected in Schedule 126, which became effective January 1, 2011.

Q. What is the final PCV after application of the deadband and sharing percents?

A. Because PGE's Annual Variance of $15.0 million is within the deadband amount of $30 million, we do not apply sharing percentages to determine a final PCV.

III. Earnings Review

Q. Has PGE performed an earnings review with which to calculate the ROE deadband?

A. Yes. We performed this review initially as part of our annual requirement to provide a Results of Operations (ROO) Report to the OPUC Staff, which we submitted on April 25, 2018. Because the ROO incorporates all aspects of the PCAM earnings review, PGE uses it as the basis for the ROE deadband. We include it as PGE Exhibit 102.

Q. What is the ROE deadband?

A. The ROE deadband is ±100 basis points of PGE's authorized ROE, which for 2017 is 9.60% (Commission Order No. 15-356). If PGE's earnings were below 8.60%, then we would collect the PCV up to the point where the ROE is 8.60%. Alternatively, if PGE's earnings were above 10.60%, then we would refund the PCV down to the point where the ROE is 10.60%.

Q. What was PGE's final 2017 ROE including the PCV?

A. PGE's final 2017 Regulated Adjusted ROE is 7.90%,[6] which is below the lower bound of the 8.60% to 9.60% earnings deadband. However, as noted in Section II. D. above, the Annual Variance is within the power cost deadbands, so the PCV is not subject to the earnings review. Consequently, there is no customer collection (or refund) associated with the 2017 PCAM.

[6] This is the earnings test result that includes the relevant adjustments from Commission Order No. 15-356 and the OPUC letter regarding the calculation of ROOs dated March 25, 1992.

Q. Does PGE provide earnings review ROE results that separately identify the impact of the PCAM amount as specified in item 4 of the UE 201 stipulation (see Commission Order No. 08-551)?

A. Yes. PGE Exhibit 104 provides the stipulated ROE results; however, because the final 2017 PCAM amount equals zero, there is no impact from this entry.

Q. What is the rate impact of the 2017 PCAM?

A. Because the 2016 PCAM also entailed no refund to or collection from customers, there is no rate impact associated with the 2017 PCAM.

IV. Qualifications

Q. Mr. Tooman, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from the Ohio State University. I received a Master of Arts degree in Economics and a Ph.D. in Economics from the University of Tennessee. I have held managerial accounting positions in a variety of industries and have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. Finally, I have worked for PGE in the Rates and Regulatory Affairs department since 1996.

Q. Mr. Batzler, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Radio and Television from San Francisco State University in 1997 and a Master of Business Administration degree from Marylhurst University in 2011. I have been employed at PGE since 2006, working in various departments including Meter Reading and Human Resources. I have worked in the Rates and Regulatory Affairs department since 2012.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	Summary Calculation of 2017 PCV
102	2017 Results of Operations as filed April 28, 2018
103C	2017 Actual Power Costs by Month and FERC Account
104	2017 Results of Operations with segregated PCAM amount

PGE Power Cost Variance Mechanism (PCAM) ($000s)

December 2017

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
BASE													
MONET NVPC ($000s)													
MONET (AUT/GRC) - Without PTCs	44,311	39,191	39,066	34,053	36,114	35,085	37,090	37,974	35,158	37,666	39,008	43,356	458,070
Production Tax Credits (PTCs)	(4,649)	(5,394)	(6,156)	(7,699)	(7,549)	(8,422)	(8,185)	(7,491)	(5,607)	(4,786)	(4,615)	(4,638)	(75,192)
MONET (AUT/GRC) (Nov15, Pre-Selection)	39,662	33,797	32,911	26,354	28,565	26,663	28,904	30,483	29,551	32,879	34,392	38,718	382,879
Nov Opt-Outs	(621)	(536)	(454)	(384)	(372)	(384)	(726)	(814)	(698)	(618)	(640)	(781)	(7,028)
NVPC (POST-SELECTION)	39,041	33,261	32,456	25,970	28,193	26,279	28,179	29,668	28,853	32,262	33,752	37,937	375,851
Adjustments for BASE NVPC													
Coyote Steam Sales in GRC - Other Rev	(328)	(172)	(191)	(185)	(191)	(223)	(224)	(191)	(207)	(198)	(185)	(191)	(2,487)
Wind Availability Damages in GRC - O&M	-	151	-	-	-	-	-	-	665	-	-	445	1,261
REVISED BASE NVPC (Post-Select, COS)	38,712	33,240	32,265	25,785	28,002	26,057	27,955	29,477	29,311	32,064	33,567	38,190	374,624
BASE LOADS (MWHs)													
ORDER Retail Loads (Pre-Selection, COS)	1,661,042	1,428,266	1,482,691	1,350,144	1,338,477	1,304,416	1,446,050	1,446,143	1,317,044	1,368,996	1,474,583	1,675,357	17,293,207
Dec Opt-Outs to ORDER Retail Loads	(22,106)	(20,507)	(22,268)	(21,239)	(21,892)	(23,218)	(24,321)	(24,864)	(21,989)	(22,919)	(21,300)	(21,685)	(268,308)
BASE LOADS (Retail, w-DEC Opt-Outs, COS)	1,638,936	1,407,759	1,460,423	1,328,905	1,316,584	1,281,198	1,421,729	1,421,278	1,295,055	1,346,077	1,453,282	1,653,672	17,024,899
BASE UNIT NVPC	23.62	23.61	22.09	19.40	21.27	20.34	19.66	20.74	22.63	23.82	23.10	23.09	22.00
ACTUALS / FORECAST	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	Actuals	
Actual / Forecast NVPC (no Other Rev)	52,195	40,253	34,838	31,472	34,884	36,502	34,776	55,693	43,022	36,830	40,607	45,819	486,891
EXCLUDE:													
FAS 133/71 - MTM/Deferral	-	-	-	-	-	-	-	-	-	-	-	-	-
Credit Reserve - Expense	-	-	36	-	-	22	-	-	-	-	-	18	76
Out-of-Period Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
Direct Access deferral amortization - 4470004	50	111	69	57	53	55	58	63	63	53	56	71	758
Green Power expenses in 4171007 & 5550006	1,367	1,190	1,066	901	841	771	914	980	994	854	928	1,612	12,417
Solar Pymt Option-SPO (was FIT) - avoided costs	375	15	17	19	65	46	-	184	-	75	46	33	874
2017 Trans amort-Revs in 2015 PCAM-Gamesa/EDF	(660)	-	-	-	-	-	-	-	-	-	-	-	(660)
Auto Demand Response deferred costs	86	93	154	-	52	-	-	-	-	-	510	-	895
Carty Lateral Capital Lease reclass to O&M	(344)	(344)	(343)	(342)	(341)	(340)	(339)	(338)	(337)	(336)	(335)	(334)	(4,072)
Subtotal Exclusions	873	1,065	999	636	670	554	633	889	720	646	1,205	1,400	10,290
INCLUDE:													
Coyote Steam Sales - 4560012	(127)	(131)	(152)	(123)	(141)	(141)	(188)	(170)	(195)	(205)	(135)	(185)	(1,892)
Gas Resale Margin - 4560008	(139)	(332)	(1,290)	(1,478)	(1,061)	(956)	29	4	(20)	13	(227)	(96)	(5,551)
Wind availability (damages)/bonus - 5490001	-	-	(1)	-	-	-	-	-	-	-	(113)	638	524
Energy Revenues from VPO customers	(445)	(283)	(178)	(128)	(178)	(169)	(406)	(662)	(410)	(341)	(298)	(322)	(3,821)
Transmission resale revenues	(556)	(504)	(733)	(968)	(972)	(920)	(570)	(455)	(507)	(452)	(746)	(727)	(8,110)
Thermal plant chemicals in O&M	804	574	388	363	228	83	297	885	496	552	339	502	5,511
Production Tax Credits-PTCs- in Taxes	(1,566)	(4,027)	(6,143)	(6,699)	(4,909)	(7,180)	(8,838)	(5,820)	(4,595)	(6,242)	(4,562)	(2,691)	(63,271)
Subtotal Inclusions	(2,028)	(4,701)	(8,108)	(9,034)	(7,034)	(9,284)	(9,675)	(6,218)	(5,231)	(6,675)	(5,741)	(2,880)	(76,610)
REVISED ACTUAL NVPC	49,294	34,487	25,731	21,802	27,180	26,664	24,467	48,585	37,071	29,510	33,661	41,539	399,990
ACTUAL LOADS (Retail-COS-Calendar)	1,819,118	1,473,861	1,474,661	1,314,464	1,320,742	1,300,687	1,421,431	1,561,635	1,360,131	1,311,866	1,428,106	1,708,415	17,495,118
ytd	1,819,118	3,292,979	4,767,641	6,082,105	7,402,847	8,703,534	10,124,965	11,686,599	13,046,731	14,358,597	15,786,703	17,495,118	
ACTUAL UNIT NVPC	27.10	23.40	17.45	16.59	20.58	20.50	17.21	31.11	27.26	22.49	23.57	24.31	22.86
UNIT NVPC VARIANCE													
ACTUAL UNIT NVPC	27.10	23.40	17.45	16.59	20.58	20.50	17.21	31.11	27.26	22.49	23.57	24.31	22.86
BASE UNIT NVPC	23.62	23.61	22.09	19.40	21.27	20.34	19.66	20.74	22.63	23.82	23.10	23.09	22.00
ACTUALS ABOVE (BELOW) BASE UNIT NVPC	3.48	(0.21)	(4.64)	(2.82)	(0.69)	0.16	(2.45)	10.37	4.62	(1.33)	0.47	1.22	0.86
ANNUAL VARIANCE (AV) = UNIT NVPC VARIANCE X ACTUAL LOADS													
ACTUALS ABOVE (BELOW) BASE	6,326	(314)	(6,849)	(3,703)	(910)	211	(3,482)	16,198	6,287	(1,739)	675	2,084	15,019
ACTUALS ABOVE (BELOW) BASE - YTD	6,326	6,012	(837)	(4,540)	(5,449)	(5,238)	(8,720)	7,478	13,765	12,025	12,700		
Positive Deadband - Actuals ABOVE Base	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Negative Deadband - Actuals BELOW Base	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)
Variance at 100%	-	-	-	-	-	-	-	-	-	-	-	-	
ANNUAL POWER COST VARIANCE (PCV) = (ANNUAL VARIANCE - DEADBAND) X 90%													
YTD POWER COST VARIANCE (PCV) = (YTD VARIANCE - DEADBAND) X 90%												POSITIVE (NEGATIVE) PCV = ACTUALS ABOVE (BELOW) POWER COST DEADBANDS	-

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2017 - December 31, 2017
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE 294, Order 15-356**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	Type II Adjustments	Pro Forma Results
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,858,861	(131)	1,858,730	(3,560)	1,855,169	7,392	1,862,562
Sales for Resale	116,335	(116,335)	0	0	0	0	0
Other Operating Revenues	41,241	(15,554)	25,687	0	25,687	0	25,687
Total Operating Revenues	2,016,437	(132,021)	1,884,417	(3,560)	1,880,856	7,392	1,888,249
Operation & Maintenance							
Net Variable Power Cost	601,778	(127,158)	474,621	0	474,621	(13,169)	461,452
Total Fixed O&M	304,629	(3,326)	301,302	0	301,302	3,625	304,928
Other O&M	262,416	957	263,373	(16,733)	246,640	2,334	248,973
Total Operation & Maintenance	1,168,823	(129,527)	1,039,296	(16,733)	1,022,563	(7,210)	1,015,353
Depreciation & Amortization	342,742	0	342,742	(4,556)	338,186	1,830	340,016
Other Taxes / Franchise Fee	122,375	(745)	121,630	(91)	121,539	1,157	122,696
Income Taxes	85,026	(1,943)	83,083	8,343	91,426	5,630	97,056
Total Oper. Expenses & Taxes	1,718,966	(132,216)	1,586,751	(13,037)	1,573,714	1,406	1,575,120
Utility Operating Income	297,471	195	297,666	9,476	307,142	5,986	313,128
Rate of Return	6.27%		6.27%		6.65%		6.92%
Return on Equity	7.17%		7.17%		7.90%		8.64%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	9,845,463	0	9,845,463	(123,295)	9,722,168	146,314	9,868,481
Accumulated Depreciation	4,532,983	0	4,532,983	0	4,532,983	226,954	4,759,937
Accumulated Def. Income Taxes	645,373	0	645,373	0	645,373	14,492	659,865
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	4,667,107	0	4,667,107	(123,295)	4,543,813	(95,133)	4,448,680
Deferred Programs & Investments	24,315	0	24,315	0	24,315	(5,998)	18,317
Operating Materials & Fuel	76,473	0	76,473	0	76,473	2,378	78,851
Misc. Deferred Credits	(80,099)	0	(80,099)	0	(80,099)	(36)	(80,135)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	57,429	(12)	57,417	(473)	56,944	830	57,774
Total Average Rate Base	4,745,226	(12)	4,745,214	(123,768)	4,621,446	(97,959)	4,523,487

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2017 - December 31, 2017
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE 294, Order 15-356**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	2017 PCAM	Adjsuted Results with PCAM
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Operating Revenues							
Sales to Consumers	1,858,861	(131)	1,858,730	(3,560)	1,855,169	0	1,855,169
Sales for Resale	116,335	(116,335)	0	0	0	0	0
Other Operating Revenues	41,241	(15,554)	25,687	0	25,687	0	25,687
Total Operating Revenues	2,016,437	(132,021)	1,884,417	(3,560)	1,880,856	0	1,880,856
Operation & Maintenance							
Net Variable Power Cost	601,778	(127,158)	474,621	0	474,621	0	474,621
Total Fixed O&M	304,629	(3,326)	301,302	0	301,302	0	301,302
Other O&M	262,416	957	263,373	(16,733)	246,640	0	246,640
Total Operation & Maintenance	1,168,823	(129,527)	1,039,296	(16,733)	1,022,563	0	1,022,563
Depreciation & Amortization	342,742	0	342,742	(4,556)	338,186	0	338,186
Other Taxes / Franchise Fee	122,375	(745)	121,630	(91)	121,539	0	121,539
Income Taxes	85,026	(1,943)	83,083	8,343	91,426	0	91,426
Total Oper. Expenses & Taxes	1,718,966	(132,216)	1,586,751	(13,037)	1,573,714	0	1,573,714
Utility Operating Income	297,471	195	297,666	9,476	307,142	0	307,142
Rate of Return	6.27%		6.27%		6.65%		6.65%
Return on Equity	7.17%		7.17%		7.90%		8.64%
ROE based on actual capital structure.							
Average Rate Base							
Utility Plant in Service	9,845,463	0	9,845,463	(123,295)	9,722,168	0	9,722,168
Accumulated Depreciation	4,532,983	0	4,532,983	0	4,532,983	0	4,532,983
Accumulated Def. Income Taxes	645,373	0	645,373	0	645,373	0	645,373
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	4,667,107	0	4,667,107	(123,295)	4,543,813	0	4,543,813
Deferred Programs & Investments	24,315	0	24,315	0	24,315	0	24,315
Operating Materials & Fuel	76,473	0	76,473	0	76,473	0	76,473
Misc. Deferred Credits	(80,099)	0	(80,099)	0	(80,099)	0	(80,099)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	57,429	(12)	57,417	(473)	56,944	0	56,944
Total Average Rate Base	4,745,226	(12)	4,745,214	(123,768)	4,621,446	0	4,621,446