Oregon
Kate Brown, Governor

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August 14, 2015

Via Electronic Filing and US Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
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Docket No. UE 294 – In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

Enclosed is OPUC Commission Staff Testimony in Support of the Partial Stipulation.

The following exhibits are confidential and is being mailed separately to parties who have signed Protective Order No. 15-036.

Exhibit 1300, Page 2 and 4
Exhibit 1302, Page 3

Exhibit 1600, Page 2 and

Exhibit 1702

A copy of UE294 Service List and Certificate of Service are included with this filing.

/s/ Kay Barnes
Filing on Behalf of OPUC Commission Staff
(503) 378-5763
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CERTIFICATE OF SERVICE

UE 294

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 14th day of August, 2015 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
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CASE: UE 294
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1000

STAFF TESTIMONY IN SUPPORT OF THE PARTIAL STIPULATION

August 14, 2015

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

A. My name is Marianne Gardner. I am a Senior Revenue Requirement Analyst with the Public Utility Commission of Oregon. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301-3612.

Q. Have you filed testimony in this proceeding?

A. Yes, I filed opening testimony Exhibit Staff/700; my qualification statement is provided in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide additional information for specific issues in support of the Partial Stipulation (Stipulation) and the joint testimony filed by the Parties in this docket.

Q. Does this Stipulation indicate that all parties agree on the calculations or bases employed by other parties to determine each adjustment?

A. No, although the Stipulating Parties may not necessarily agree on the calculations, assumptions, or bases used to determine each adjustment, we believe the stipulated amounts represent a reasonable financial settlement of the respective issues in this docket. The adjustments are in the public interest, and are consistent with rates that are fair, just, and reasonable.

Q. Are other Staff submitting testimony in support of the Stipulation?

A. Yes, on the following page is a listing of Staff who are submitting separate testimony in support of the settled issues.

Issues	Staff Witness	Description	Exhibit No.
S-1, S-4, S-11	Marianne Gardner	Revenue Sensitive and Uncollectibles; Wages and Salaries; Escalation	1000
S-12	Michael Breish	Energy Efficiency	1100
S-5	Mitch Moore	Advertising	1200
S-7, S-8	Brian Bahr	Medical Benefits; Pensions	1300
S-9, I-2, I-7	Judy Johnson	Dues and Donations; Construction Overheads; Coal Inventory	1400
S-13	George Compton	Research and Development	1500
S-6	Linnea Wittekind	Various A&G; D&O Insurance	1600
S-10, I-3	Jorge Ordonez	Capital Additions; Carty Generation Station	1700
S-15	Phil Boyle	Fee Free Bankcard Program	1800

Q. How is your testimony organized?

A. My testimony is organized as follows:

S-1, Revenue Sensitive, and Uncollectibles

Q. What was PGE's filed position on Revenue Sensitive and Uncollectibles.

A. PGE proposed an uncollectible rate of 0.4700% based on a three-year average of 2014 actuals, 2015 budgeted, and 2016 forecasted test year net-write offs to the average general revenues. PGE's calculation of the uncollectible rate included bad debts (non-light and power) unrelated to retail sales.

Q. Did Staff agree with PGE's calculation?

A. No. Staff issued approximately nine data requests and reviewed PGE's responses. Staff does not support counting non-light and power uncollectibles in net-write offs, and the Company's use of budgeted and forecasted amounts for the calculation. Historically, the Commission has used a three-year average of actual net write-offs (light and power), and the related general revenues to calculate the uncollectible rate. Based on Commission policy and PGE's response to Staff DR 278(a), Staff calculated an uncollectible rate of 0.4032%.

Q. What was the parties' resolution for settlement purposes?

A. For purposes of settlement, parties agreed to accept Staff's proposed rate of 0.4032% for revenue sensitive calculations. So, while this revised uncollectible rate will change the net-to-gross factor, the parties did not agree to any specific reduction in uncollectible expenses for the test year.

S-4, Wages and Salaries

Q. What was PGE's filed position on Wages and Salaries?

A. PGE proposed an increase of 91 FTE between 2014 and the 2016 test year. In the Company's filed testimony, PGE cited a number of causes including the Company's ten percent share increase in Boardman ownership, training critical positions due to retirements, intensifying regulatory demands for cyber security, and supporting a growing IT user base combined with systems that are more complex. In addition, PGE forecasted/escalated the 2016 wages around a market-based pay structure estimating a median based on that research. Lastly, PGE removed all of its forecasted officers' stock incentive plan and 50 percent of all other forecasted employee incentives.

Q. Did Staff agree with PGE's forecast?

A. No. Staff reviewed PGE's testimony, PGE's responses to Staff's standard data requests, and issued approximately 22 additional data requests. Consistent with past Commission policy, Staff utilized Staff's three-year model to estimate a reasonable increase in wages and salaries. In this case, Staff's model escalated the historic 2013 year based on the All-Urban CPI (CPI) as published by the Oregon Dept. of Administrative Services, Office of Economic Analysis, in March 2015. (This is consistent with Commission Order No. 01-787 at 40; Order No. 99-697 at 43; Order No. 99-033 at 61; and Order No. 95-322 at 10.)

Staff also proposed elimination of the officers' incentives that remained in PGE's test year. This treatment corresponds with Commission's policy to disallow 100 percent of officers' bonuses, because these incentives are predicated on increased earnings. (Commission Order No. 99-033 at 62; Order No. 97-171 at 74-76.) Based on Commission policy, Staff routinely disallows 50 percent of merit-based bonuses, contending this type of bonus equally benefits shareholders and ratepayers. (Commission Order No. 99-697 at 44-45; Order No. 99-033 at 62.) Staff was satisfied with PGE's 50 percent reduction of non-officer incentives for the 2016 test year.

Finally, based on Staff's examination of the year-over-year trend of actual FTE, Staff proposed a reduction in PGE's estimation of FTE because it finds the FTE count was over-stated in the Company's filed case.

Q. Were parties able to reach an agreement for a 2016 test year Wages and Salaries adjustment?

A. Yes. The parties agreed to settle S-4, Wages and Salaries, collectively with other items Staff had identified for an overall reduction in revenue expense and in rate base. Staff considers the settled amount reasonable and consistent with past Commission precedent.

<u>S-11, Escalation</u>

Q. Please describe PGE's position on escalation.

A. PGE applied escalation rates to the 2015 budgeted amount for certain cost element groupings. The groups and the respective rates are as follows:

1. Labor – 3 percent;
2. Outside Services – 3 percent;
3. Direct Materials – 2 percent; and,
4. Employee Business Expense – 1.6 percent.

According to its filed testimony, the Company relied on various sources such as Global Insights; U.S. Economic Outlook dated September 2014 to develop the above rates.

Q. Did Staff agree with PGE's adjustment?

A. No. Staff disagreed and proposed an alternative calculation. Staff has historically used the All Urban CPI index (CPI) to inflate or deflate the most recent year of actual O&M and A&G costs, outside of known and measurable adjustments. Because Staff proposed a separate adjustment for labor in S-4, this adjustment is only for the expenses designated as outside services, direct materials, and employee business expense by PGE. Similar to the Wage and Salary model, Staff proposed to use the average change in CPI. In this instance, Staff applied the CPI change for 2015 and 2016 to escalate 2014 actual expense. Staff believes that the CPI is a representative measure of price change for the types of expenses included in these categories. Staff issued two data requests as part of the analysis.

Q. Were parties able to reach an agreement for a 2016 test year escalation adjustment?

A. Yes. Although parties did not specifically agree to the ideal index or base year for escalation, parties agreed to settle this adjustment in combination with a group of issues. While a specific amount was not singled out for the escalation adjustment, in Staff's opinion, the collective amount for settlement is equitable.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: MICHAEL BREISH

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

STAFF TESTIMONY IN SUPPORT OF THE PARTIAL STIPULATION

August 14, 2015

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

A. My name is Michael Breish. I am a Utility Analyst in the Energy – Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. This testimony presents my analysis concerning Portland General Electric's (PGE's) energy efficiency and other demand-side management (DSM) programs and supports the partial stipulation between the parties filed on June 23, 2015.

Q. Did you prepare an exhibit for this docket other than your qualifications exhibit?

A. Yes. I prepared the following exhibit:

Exhibit Staff/1102, PGE Data Request Responses, consisting of nine pages.

Q. Please briefly summarize your analysis of the energy efficiency and other DSM program expenditures.

A. PGE included in its UE 294 filing $282,221 in 2016 expenses for DSM research and development (R&D) programs.[1] In my analysis of PGE's DSM program expenditures, I identified two general R&D programs, "Pricing Programs Development" and "Time of Use Program," as having a limited research or pilot

[1] See Exhibit Staff/1102, at page 3, PGE Response to Staff Data Request Number 272.

program period. In addition, for these two programs, PGE spent less than what was budgeted over the 2012-2014 period.

Issue 1, Energy Efficiency and other DSM Expenditures

Q. How did Staff conduct its analysis of PGE's energy efficiency and other DSM expenditures?

A. Staff began its analysis by asking PGE a series of data requests that were intended to generate a list of all DSM-related expenses or costs that are not covered through the DSM-related tariffs and instead are included in PGE's revenue requirement. PGE responded with a list of seven programs and their associated 2014 actual expenditures and budgeted amounts for 2015 and 2016.[2] PGE also provided a list of all DSM-related accounts that included the seven programs listed in the response to Staff data request number 272.[3]

Staff correlated PGE's proposed budget increases for certain programs to the planned pilots and program development presented and discussed in PGE's 2015 Smart Grid Report.[4] Within the report is an Appendix titled "Pricing & Residential Demand Response Pilots," in which PGE describes DSM pilots to be implemented in the next few years. These align with program descriptions provided in PGE's response to Staff Data Request number 272.

[2] See Exhibit Staff/1102, pages 1-3, PGE Response to Staff Data Request number 272.
[3] See Exhibit Staff/1102, pages 4-5, PGE Response to Staff Data Request number 273.
[4] See Docket No. UM 1657, "2015 Smart Grid Annual Report," (May 28, 2015) p. 92.

Q. What are Staff's findings regarding the budgeted expenditures for the DSM programs?

A. Staff analyzed the Company's list and found that PGE increased the budgets of two programs, "General Demand Response" and "Time of Use Program," by a factor of approximately two and 33, respectively, when compared to 2014 actuals.[5] In addition, Staff found that on a yearly basis from 2012 to 2014, PGE spent less than what was budgeted for a number of DSM R&D programs, including the two programs specifically identified by Staff. In other words, PGE only spent 70 percent of the Pricing Program budget and 13 percent of the Time of Use Program budget over the 2012-2014 period.[6]

Q. Is the list of DSM programs that Staff reviewed comprehensive?

A. Yes. In order to be sure that all pertinent DSM expenditures and activity were accounted for, Staff submitted additional data requests to PGE requesting all DSM activity "paid for by customers not through monies collected and transferred by legislative directive to ETO". Staff was satisfied with the results of comparison between the Company's responses to Staff Data Request numbers 272 and 273 with responses to these additional data requests, Data Request numbers 405 and 407.[7]

[5] See Exhibit Staff/1102, at page 3, PGE response to data request number 272.
[6] See Exhibit Staff/1102, at page 9, PGE Response to Data Request number 407.
[7] See Exhibit Staff/1102, at pages 6-9, PGE response to data request numbers 405 and 407.

Q. Did the Parties reach settlement on the energy efficiency and other demand-side management (DSM) programs?

A. Yes. The Parties agreed that $237,000 should be removed from PGE"s revenue requirement request. The adjustment takes into account what Staff viewed as an overstatement of projected 2016 costs related to the programs discussed above.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: MICHAEL BREISH

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualification Statement

August 14, 2015

WITNESS QUALIFICATION STATEMENT

NAME:	Michael Breish
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, Oregon 97301-3612
EDUCATION:	Bachelor of Science, Atmosphere/Energy Engineering, Stanford University 2012
EXPERIENCE:	I have been employed as a Utility Analyst at the Public Utility Commission since September, 2014. My current responsibilities include analysis, policy and technical support for energy resource planning related proceedings, with an emphasis on integrated resource plans and demand-side management filings. Prior to working for the OPUC I was an analyst instructor at Boston Pacific Company, a consulting firm located in Washington DC, where I worked on a number of electricity-industry related cases including retail and wholesale markets, RTO/ISO practices, offshore wind development, and federal preemption cases involving state commissions and in-state power generation.

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CASE: UE 294
WITNESS: MICHAEL BREISH

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Exhibits in Support of
Staff Testimony

August 14, 2015

CASE: UE 294
WITNESS: MICHAEL BREISH

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Exhibits in Support of
Staff Testimony

August 14, 2015

March 31, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 272
Dated March 17, 2015

Request:

For the base period 2014, projected year 2015 and test period, please describe the categories of all DSM-related expenses or costs that are not covered through the DSM-related tariffs and instead are part of the company's revenue requirement in this general rate case. Please indicate the applicable accounts for each expense or cost.

Response:

For PGE's definition of Demand Side Management (DSM), please see PGE's response to OPUC Data Request No. 271.

PGE also has DSM-related programs that do not have cost recovery through supplemental schedules. These include past pilots, pricing, demand response, and residential customer energy management programs being researched and developed but not yet offered to customers. These programs include:

- Demand Response Phase FAST Demo - closed water heater pilot.
- Flex Price Pilot - closed Critical Peak Pricing pilot. This pilot was implemented to comply with a condition identified in Commission Order NoI. 08-245 and related to PGE's advance metering infrastructure system (AMI).
- General Demand Response - research into demand response programs, technology, and customer participation.
- Pricing Programs Development - peak time rebate, smart thermostat. These are currently under discussion in Docket No. UM 1708.

- Time of Use Program - program management of TOU offered to residential and small commercial customers, Schedules 7 and 32 respectively.
- Energy Tracker (also known as information driven energy savings; IDES) - residential and small commercial customer management of energy use, development, enhancement work. This program was implemented based on an AMI condition identified in Commission Order No. 08-245.
- Energy Information Services.

Expenses for these programs consist of costs for developing pricing programs with associated consultant fees, plus costs to run the DSM programs, which are not deferred and collected through supplemental schedules (see PGE's response to OPUC Data Request No. 271). These expenses are accounted for in FERC Account 903 and 908; which are part of PGE's revenue requirement.

Attachment 272-A provides a list of the DSM-related programs and their associated account numbers to which the costs are charged for the period of 2014 to 2016.

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Non Tariffed DMS - DR272

account	account_desc	awo_desc	Act_2014	Bud_2015	Bud_2016	Total
9030001	**CustAcct-CustRecords&Collect**	Flex Price Pilot (CPP)	$ 78,034	$ -	$ -	$ 78,034
9080001	**CustSvc-CustomerAssistanceExp**	Demand Response Phase FAST Demo	$ 5,100	$ -	$ -	$ 5,100
9080001	**CustSvc-CustomerAssistanceExp**	Flex Price Pilot (CPP)	$ 5,698	$ -	$ -	$ 5,698
9080001	**CustSvc-CustomerAssistanceExp**	General Demand Response	$ 41,389	$ 32,000	$ 32,932	$ 106,321
9080001	**CustSvc-CustomerAssistanceExp**	Pricing Programs Development	$ 65,545	$ 137,000	$ 140,980	$ 343,525
9080001	**CustSvc-CustomerAssistanceExp**	Time of Use Program	$ 2,751	$ 93,361	$ 95,977	$ 192,089
9080001	**CustSvc-CustomerAssistanceExp**	Energy Tracker (IDES)	$ 1,666	$ 12,000	$ 12,332	$ 25,998
Grand Total			**$ 200,182**	**$ 274,361**	**$ 282,221**	**$ 756,764**

March 31, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 273
Dated March 17, 2015

Request:

Please provide numerically each total dollar amount for the historical base year and the three previous years by category of DSM. Please indicate the applicable accounts for each expense or cost.

Response:

PGE's definition of Demand Side Management (DSM) programs is found in PGE's response to OPUC Data Request No. 271.

Attachment 273-A provides a list of DSM-related programs for the period of 2012 to 2016 and includes related accounts and costs for each program.

Note: Due to the completion of PGE's financial system replacement, project in April 2011 replacement project of PGE's Financial System that concluded in 2011, program data for 2011 is limited to post-April financial results. Therefore, Attachment 273-A provides calendar year data for 2012 through to 2016.

account	awo desc	Act 2012	Act 2013	Act 2014	Bud 2015	Bud 2016
1823001	Automated Demand Response	19,133	0	0	0	0
1823002	ADR Deferred Costs	0	175,408	(57,908)	0	1,678,176
1823002	Automated Demand Response	0	19,788	0	0	0
1840004	ADR - Non-Deferred Costs	0	0	16,144	0	0
2420008	ADR Deferred Costs	0	0	(3,227,923)	2,186,241	0
4210010	ADR Deferred Costs	0	(5,258)	142	0	0
4310002	ADR Deferred Costs	0	0	27,894	44,678	0
4560002	ADR Deferred Costs	0	0	3,205,145	(2,230,919)	0
5550019	ADR Deferred Costs	0	0	366,288	2,160,918	0
5860001	ADR - Non-Deferred Costs	0	0	346	28,270	34,821
9030001	Automated Demand Response	4,965	0	0	0	0
9030001	Demand Response - Price Server	1,921	0	0	0	0
9030001	Demand Response Phase FAST Demo	0	23	0	0	0
9030001	Energy Tracker Software - expense	139,772	7,646	0	0	0
9030001	Flex Price Pilot (CPP)	49,325	118,241	78,034	0	0
9030001	Flex Rate Pricing Plan	2,024	0	0	0	0
9030001	Pricing Programs Development	3,468	6,119	0	0	0
9030001	Time of Use Program	0	50	0	0	0
9080001	ADR - Non-Deferred Costs	0	36,461	38,975	1,000	1,016
9080001	ADR Deferred Costs	0	51	359,429	70,001	0
9080001	Auto Demand Resp - Vendor Select	8,468	16,066	7,824	0	0
9080001	Automated Demand Response	18,851	8,547	0	0	0
9080001	Demand Response - Price Server	3,160	0	0	0	0
9080001	Demand Response Phase FAST Demo	37,018	31,058	5,100	0	0
9080001	Energy Tracker (IDES)	31,289	0	1,666	12,000	12,332
9080001	Energy Tracker Software - Design	310	0	0	0	0
9080001	Energy Tracker Software - expense	28	0	0	0	0
9080001	Energy Tracker, SW - Config/Test	29	0	0	0	0
9080001	Flex Price Pilot (CPP)	20,518	42,143	5,698	0	0
9080001	Flex Rate Pricing Plan	55,028	0	0	0	0
9080001	General Demand Response	61,866	48,047	41,389	32,000	32,932
9080001	Pricing Programs Development	9,373	2,395	65,545	137,000	140,980
9080001	Time of Use Program	4,611	2,636	2,751	93,361	95,977
9200002	ADR - Non-Deferred Costs	0	45,669	14,854	176,683	151,769
9200002	Automated Demand Response	6,285	0	0	0	0
9200002	Flex Price Pilot (CPP)	13,834	790	0	0	0
9200002	Flex Rate Pricing Plan	8,292	0	0	0	0
9200002	General Demand Response	129	0	0	0	0
9210001	ADR - Non-Deferred Costs	0	0	90	0	0
9210002	ADR - Non-Deferred Costs	0	1,237	0	0	0
9210002	ADR Deferred Costs	0	0	15	0	0
9230001	ADR Deferred Costs	0	4,095	0	0	0
Grand Total		**499,696**	**561,212**	**951,497**	**2,711,233**	**2,148,003**

April 29, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 405
Dated April 15, 2015

Request:

In the following table format, please provide every energy efficiency program, demand response program, and conservation program administered by the Company and paid for by customers not through monies collected and transferred by legislative directive to the ETO. Please also include whether each program is funded by a tariff or by general rates. If the former, please indicate the exact tariff. Please include company expenditures for the three years prior to the base year, if applicable, the base year, projected year and test period year.

Program Name	Tariff or General Rate	2011	2012	2013	2014	2015	2016

Response:

Table 1 below provides a list of PGE's Energy Efficiency (EE) programs that are collected through tariffed EE schedules or through base rates. Program expenditures are provided for each of the programs under the respective year.

NOTE: Due to the completion of PGE's financial system replacement project in April 2011, program data for 2011 is not provided. Therefore, Table 1 below provides calendar year data for 2012 through to 2016.

Program Name	Tariff Schedule or Base Rates	Expected Costs (budgeted)			Actuals Budget	
		2012	2013	2014	2015	2016
ADR - Non-Deferred Costs	Base Rates	0	83,367	70,409	205,953	187,606
ADR Deferred Costs	Schedule 135	0	174,297	555,582	2,230,919	1,678,176
Automated Demand Response	Base Rates	56,297	12,519	0	0	0
Demand Response - Price Server	Base Rates	5,841	0	0	0	0
Demand Response Phase FAST Demo	Base Rates	41,383	34,263	5,100	0	0
Energy Info & Pricing Strategy	Base Rates	0	42,113	30,292	0	0
Energy Tracker (IDES)	Base Rates	31,289	0	1,666	12,000	12,332
Energy Tracker Software - Design	Base Rates	310	0	0	0	0
Energy Tracker Software - expense	Base Rates	139,800	7,646	0	0	0
Flex Price Pilot (CPP)	Base Rates	98,075	189,751	103,566	0	0
Flex Rate Pricing Plan	Base Rates	74,379	0	0	0	0
General Demand Response	Base Rates	67,055	54,534	46,591	32,000	32,932
Schedule 77, Load Curtailment Program KB404	Base Rates	18,543	39,932	39,979	1,979	2,025
Pricing Programs Development	Base Rates	14,936	9,653	187,339	137,000	140,980
Time of Use Program	Base Rates	5,278	2,934	3,698	93,361	95,977

April 29, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 407
Dated April 15, 2015

Request:

In the following table format, for those programs identified by the Company in data request 405, please indicate the Company's expected cost, i.e. what was budgeted, versus what the actual cost of each program.

Program Name	Expected Cost (budgeted)				Actual Cost			
	2011	**2012**	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**

Response:

Table 1 below provides a list of PGE's Energy Efficiency (EE) programs and the expected costs (budgeted) and actual costs for each program under each respective year.

NOTE: Due to the completion of PGE's financial system replacement project in April 2011, program data for 2011 is not provided. Therefore, Table 1 below provides calendar year data for 2012 through to 2016.

Table 1						
Program Name	**Expected Costs (budgeted)**			**Actual Costs**		
	2012	**2013**	**2014**	**2012**	**2013**	**2014**
ADR - Non-Deferred Costs	-	-	173,647	0	83,367	70,409
ADR Deferred Costs	-	-	1,659,007	0	174,297	555,582
Automated Demand Response	3,306,567	-	-	56,297	12,519	0
Demand Response - Price Server	139,116	-	-	5,841	0	0
Demand Response Phase FAST Demo	17,026	8,706	-	41,383	34,263	5,100
Energy Info & Pricing Strategy	-	268,526	100,940	0	42,113	30,292
Energy Tracker (IDES)	-	32,016	-	31,289	0	1,666
Energy Tracker Software - Design	129,857	-	-	310	0	0
Energy Tracker Software - expense	73,647	-	-	139,800	7,646	0
Flex Price Pilot (CPP)	-	150,905	-	98,075	189,751	103,566
Flex Rate Pricing Plan	-	-	-	74,379	0	0
General Demand Response	101,594	53,118	35,100	67,055	54,534	46,591
Schedule 77, Load Curtailment Program KB404	120,450	12,672	2,000	18,543	39,932	39,979
Pricing Programs Development	89,148	64,016	151,500	14,936	9,653	187,339
Time of Use Program	24,610	48,176	16,160	5,278	2,934	3,698

CASE: UE 294
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

STAFF TESTIMONY IN SUPPORT OF THE PARTIAL STIPULATION

August 14, 2015

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

A. My name is Mitchell Moore. I am a Senior Utility Analyst with the Public Utility Commission of Oregon (Commission). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the partial stipulation in this docket that includes the areas of advertising, promotions and customer service.

Q. Did you prepare an exhibit for this docket other than your qualifications exhibit?

A. Yes. Exhibit Staff/1202 contains PGE's response to Standard Data Request #104, in which the Company provides supporting detail regarding its advertising and marketing budget.

Q. How is your testimony organized?

A. My testimony addresses advertising and customer service related expense. In my testimony, I will discuss the historical treatment of the issue, describe my analysis, and explain how this issue is addressed in the partial stipulation.

Advertising

Q. Does the Commission have a standard means of defining how advertising-related expenses are treated?

A. Yes, it does. OAR 860-026-0022 sets out how advertising-related expenses are addressed in a rate case.

Q. How did Staff perform its analysis of PGE's proposed advertising expenses?

A. Staff reviewed the Company's response to a standard data request, in which PGE provided a breakdown of its proposed 2016 advertising budget by category, and Staff reviewed the transaction-level detail of the Company's 2014 spending on advertising and marketing activities.

Q. What did the Company propose to spend in its initial filing on advertising in its 2016 budget?

A. For its 2016 advertising budget, PGE included the following:[1]

FERC Account	PGE Account	Account Description	Budget 2016	Category
909.0	9090001	Informational Advertising	$2,087,673	A
909.0	9090001	Legally Mandated Advertising	$25,750	B
930.1	9301001	Institutional/Promotional Advertising	($732,708)	C*
417.1	4171003	Political/Non-Utility Advertising	$0	D**
417.1	4171005	Political/Non-Utility Advertising	$12,360	D**
182.3		EE & Conservation Advertising	$0	E
		2016 Advertising Budget	$2,858,491	

* Remove 100% of Account 9301001
** Not included in base rates

[1] See Staff Exhibit/1202, PGE's response to Staff Data Request #104.

Q. What is Staff's assessment of PGE's proposed 2016 advertising budget?

A. Advertising categories are excluded from base rates in a manner consistent with the Commission's rule, OAR 860-026-0022.

Q. Please explain how Staff came to this conclusion.

A. According to OAR 860-026-0022, Category A expenses are presumed reasonable if they are within 0.125 percent of the revenue requirement. Staff agrees that PGE's proposed Category A budget of $2.1 million is consistent with the rule. In addition, the proposed budget for spending in this category is flat, relative to the Company's actual spending in 2012-2014.

Category B spending on legally mandated advertising is presumed just and reasonable, according to the rule. Here again, PGE's proposed spending is consistent with actual spending in 2012-2014.

For Category C spending, for which the Company must provide justification as to its reasonableness, the Company in its initial filing removed this amount from the revenue requirement.

Category D expenses are also excluded from the revenue requirement.

The Company proposes no spending on Category E advertising – energy efficiency and conservation.

Q. How did Staff analyze advertising expense at the transaction-level?

A. Staff reviewed all transactions in FERC accounts relating to advertising and marketing for the 2014 base year. In FERC account 908, Staff identified advertising-related transactions that would not have been justified and accounted for in PGE's proposed 2016 advertising budget. The account also contained miscellaneous items such as gift cards, flowers, and party favors – expenses that Staff does not support including in establishing the Company's base rates. Staff identified an additional amount of business meals as expenses that should not be included, which is in accordance with Commission Order 09-020 that allows the Company to include only 50 percent of these expenses. Staff typically removes these expenses and then scales up according to the March 2015 All Urban Consumer Price Index.

Q. What types of transactions are recorded in FERC account 908?

A. FERC account 908 is used for transactions related to labor, materials and expenses the utility incurs in providing instruction or assistance to customers.

Q. Did Staff identify issues with the other accounts that contain advertising-related expense?

A. No. Upon review, Staff found that the advertising expenses in FERC accounts 909, 930.1, 417.1, and 182.3 were consistent with prior years' spending, and fell within the Commission's prescribed parameters contained in OAR 860-026-0022.

Q. How is the issue of advertising expense resolved in the Partial Stipulation?

A. Under the Partial Stipulation, the Parties agree to remove approximately $70,000 from PGE's revenue requirement request.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualification Statement

August 14, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mitchell Moore
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit
ADDRESS:	201 High Street SE. Suite 100 Salem Oregon 97301-3612
EDUCATION:	Bachelor of Arts, Journalism and Political Science University of Hawaii at Manoa (1992)
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division. My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints. Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UE 294
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202
Advertising Budget

Exhibits in Support
Of Staff Testimony

August 14, 2015

2016 Advertising Budget

FERC Account	PGE Account	Account Description	Budget 2016	Category
909.0	9090001	Informational Advertising	$2,087,673	A
909.0	9090001	Legally Mandated Advertising	$25,750	B
930.1	9301001	Institutional/Promotional Advertising	$732,708	C*
417.1	4171003	Political/Non Utility Advertising	$0	D**
417.1	4171005	Political/Non Utility Advertising	$12,360	D**
182.3		EE & Conversion Advertising	$0	E
		2016 Advertising Budget	$2,858,491	

* Remove 100% of Account 9301001

Category A Advertising Adjustment
2016 Test Year Budget

Category	A
FERC 9090001	$2,113,423
Less: Legally Mandated Advertising (Cat B)	25,750
Net Category A	$2,087,673
2016 Total Revenue Requirement	1,921,344,496
Factor per OAR	0.125% *
Presumed Reasonable Cat A Costs	2,401,681
Difference	$314,008
Adjustment	-

* OAR 860-26-022 Rule = 1/8 of 1% of sales is presumed reasonable

Category C Advertising Adjustment
2016 Test Year Budget

Category	C
Account 9301001	732,708
Adjustment %	100.0%
Decrease to A&G Costs	(732,708)

CASE: UE 294
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Opening Testimony

<u>REDACTED</u>
August 14, 2015

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

A. My name is Brian Bahr. I am a Senior Utility Analyst for the Oregon Public Utility Commission (Commission). My business address is 201 High St SE Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1301.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe my analysis of two issues that were settled in the stipulation reached between the parties in this docket on May 29, 2015. The two issues I analyzed that were settled were pension costs and medical benefits. I also analyzed affiliated interests and taxes other than income, but these will not be discussed in this testimony, as I proposed no related adjustments to the Company's filing.

Q. Did you prepare an exhibit for this docket?

A. Yes, in addition to my Witness Qualification Statement, I prepared confidential Exhibit Staff/1302, which consists of various documents Staff reviewed in connection with its analysis in support of Staff's testimony.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, PENSION COSTS

Q. Please describe the company's request regarding pension costs.

A. The Company's proposed rate increase includes a test year pension expense of approximately $25.3 million, $14.7 million of which is expensed and $10.6 million of which is capitalized.[1] Additionally, in contrast to several of the Company's most recent general rate cases, the Company is proposing to NOT include in rate base its estimated prepaid pension asset, net of its related accumulated deferred taxes.[2] The prepaid pension asset is defined as the difference between the Company's total cash payments into its pension fund and the cumulative accrual expense the Company has incurred, as calculated under Financial Accounting Standard (FAS) 87 and other relevant Generally Accepted Accounting Principles (GAAP). The Company's estimate of the December 31, 2015, prepaid pension asset balance, net of the estimated $[redacted] of accumulated deferred taxes associated with it, is approximately $[redacted].[3]

Q. How are pension costs typically treated by the Commission?

A. Though most expenses approved for inclusion in rates are based on cash costs, cash payments from a company to its pension fund can be volatile from year to year, depending on market and interest rates, as well as changing pension regulations. Because of the volatility of these cash payments, the Commission has approved the use of accrual pension costs as a proxy for

[1] *See* PGE/500, Barnett-Jaramillo/33, at line 17, and Barnett-Jaramillo/35, at line 5.
[2] *See* PGE/500, Barnett-Jaramillo/35, at line 8.
[3] *See* PGE/500, Barnett-Jaramillo/34, at line 6, and the Company's confidential response to Staff Data Request No. 232, included as confidential Exhibit Staff/1302, Bahr/1-3.

cash payments. These accrual pension costs are calculated in accordance with applicable standardized accounting guidance.

The Commission is currently conducting a general investigation into the recovery of pension costs in Docket No. UM 1633. In that docket, the Commission is investigating whether FAS 87 should be continued for use in rate recovery of pension expense, whether a company's prepaid pension asset should be included in rate base, and whether there are more effective methods of pension cost recovery than those currently in practice in Oregon.

Q. How did Staff analyze the Company's requested pension costs?

A. Staff reviewed the Company's responses to 19 Staff data requests related to pension costs as well as the testimony and supporting work papers included in the Company's filing. In analyzing the Company's requested pension costs, Staff distinguished between the two parts of the proposed cost, the requested FAS 87 expense amount and the exclusion from rate base of both the prepaid pension asset and the related accumulated deferred taxes.

As described above, the Commission has historically relied on FAS 87 expense as a reasonable representation of cash costs in any given year. The FAS 87 expense amount is calculated and determined by third-party actuaries. Though most of the calculation's inputs are based on actual costs and amounts, two of the inputs require a degree of subjective judgment; these are the expected long term market rate of return on pension assets (EROA) and the expected discount rate. Typically in reviewing pension costs as part of a general rate case, Staff analyzes these two inputs, reviews them for reasonableness, recalculates the expense, and potentially recommends an adjustment to the proposed cost based on recommended changes to the EROA or discount rate.

With regard to the Company's request to exclude from rate base the accumulated deferred taxes associated with the prepaid pension asset, Staff notes this request is dissimilar to the Company's previous two general rate cases, Commission Dockets No. UE 262 and No. UE 283. In those cases, the Company requested the prepaid pension asset be included in rate base, net of the associated accumulated deferred tax amount. Several other companies have made the same request in recent general rate cases, including NW Natural (UG 221), PacifiCorp (UE 263), and Avista (UG 246). As these rate cases have been concurrent with Docket UM 1633, the Commission's general investigation into pension cost recovery, Staff has recommended in each case that no change to current cost recovery methods is warranted until the conclusion of the general investigation.

As the balance of a prepaid pension asset grows, so also grows the balance of its associated deferred tax benefit. Staff notes that PGE, as well as the three other utility companies mentioned above, currently does not include its prepaid pension asset in rate base. However, in contrast to the other companies, PGE currently does include the associated deferred tax benefit, which reduces rate base and benefits customers. Including the deferred tax benefit would reduce rate base by approximately $[redacted].

Q. What were Staff's findings on review of the Company's proposed FAS 87 expense?

A. Staff carefully reviewed the assumptions and calculations of the third party actuary used by the Company to determine the expected test year FAS 87 expense. To compare the Company's EROA and discount rate used in the FAS 87 expense calculation to those of other utility companies regulated in Oregon, Staff constructed the following table using 2014 SEC 10k filings found online. As seen in the below table, the Company's EROA was reduced by 75 basis points between 2013 and 2014, and PGE's was the only EROA that changed over that time.

Table 1. Expected Rate of Return used in FAS 87 calculations

Company	2013	2014
Avista[4]	6.6%	6.6%
Cascade[5]	7%	7%
Idaho Power[6]	7.75%	7.75%
NW Natural[7]	7.5%	7.5%
PacifiCorp[8]	7.5%	7.5%
PGE[9]	8.25%	7.5%

[4] Avista's 2014 10k can be found online at: http://www.annualreports.com/Click/6241?_SID_=20150706190117-2fe6be35324430e88f3e9d1d6c83301a. Page 89 is included as Exhibit Staff/1302, Bahr/4.

[5] Cascade's 2014 10k can be found online at: http://www.mdu.com/docs/default-source/Proxy-Materials/2014-annual-report-10-k-and-proxy.pdf. Page 89 is included as Exhibit Staff/1302, Bahr/5.

[6] Idaho Power's 2014 10k can be found online at: http://www.idacorpinc.com/pdfs/annualreps/ar2014.pdf. Page 110 is included as Exhibit Staff/1302, Bahr/6.

[7] NW Natural's 2014 10k can be found online at: https://www.nwnatural.com/Content/AnnualReport/2014/files/10K_2014.pdf. Page 72 is included as Exhibit Staff/1302, Bahr/7.

[8] PacifiCorp's 2014 10k can be found online at: https://www.last10k.com/Search/LoadPDF?u=http://www.last10k.com/sec-filings/75594/000007559415000003/pacificorp123114form10-k.htm.pdf. Page 79 is included as Exhibit Staff/1302, Bahr/8.

Staff also compiled a table showing the Company's actual annual returns on its pension asset compared to the EROA used for each year's FAS 87 expense. The Company's actual and expected returns from 2003 through 2014 can be found in the Company's response to Staff Data Request No. 390, which is included as Exhibit Staff/1302, Bahr/10; an excerpt of the data is included in the table below.

Table 2. Expected vs. Actual Rate of Return on Pension Assets

	2009	2010	2011	2012	2013	2014
Expected ROA	8.50%	8.50%	8.25%	8.25%	8.25%	7.50%
Actual ROA	26.90%	15.02%	3.46%	17.51%	18.39%	7.90%
% Difference	216.5%	76.7%	-58.1%	112.2%	122.9%	5.3%
Actual > Expected?	Over	Over	Under	Over	Over	Over

The information contained in the response to Staff's Data Request No. 390 indicates that the Company's actual returns between the years of 1998 and 2014 exceeded the expected return in ten of 17 years, in eight out of 12 years since 2003, and five out of six years since 2009. Though past results are no guarantee of future returns, this information suggests the Company regularly exceeds its EROA used in calculating FAS 87 expense, and a significant decrease in the Company's expected rate of return is not supported.

In its testimony in the Commission's general investigation into pension costs, Docket No. UM 1633, the Company testified (emphasis added):[10]

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[9] PGE's 2014 10k can be found online at: http://files.shareholder.com/downloads/POR/401492826x0xS784977-15-5/784977/filing.pdf. Page 102 of the report is included as Exhibit Staff/1302, Bahr/9.

[10] *See* Docket No. Um 1633, PGE/100, Hager-Jaramillo/4-6, included as Exhibit Staff/1302, Bahr/11-13.

> *A projected return or expected return on assets (EROA) is a long-term estimate that is actuarially determined and <u>generally does not vary significantly from year to year</u>. Its purpose is not to accurately forecast the real market returns for the year, but rather to provide an estimate of the expected average. This average helps smooth FAS 87 expense year to year with the understanding that while actual market returns can vary widely up and down each year, over time they will average near the forecasted projections.*
>
> *<u>PGE's pension asset has consistently outperformed similarly sized pension plans for the last five years</u>, performing in the top decile of funds over the five years ending September 30, 2013. Additionally, from 2000 through 2011, PGE's pension plan performance outpaced the average pension returns of the nation's largest companies (companies listed in the 2012 Fortune 1 000) by an average of 1.2% annually. Since 1994, PGE has outperformed the market benchmark by 86 basis points on average. This is not the result of a "single year's showing of above average market performance", <u>it is the result of consistently beating the market benchmarks</u>.*

Because the Company's actual returns were consistently exceeding its expected returns, Staff concluded that a reduction in the FAS 87 expense is warranted. For example, by using a 7.75 expected return on assets instead of 7.5, the expense would be reduced by approximately $1.3 million.[11]

Q. Did Staff evaluate the Company's proposed exclusion of the accumulated deferred taxes associated with the prepaid pension asset?

A. Yes. Consistent with recent practice and Commission decisions, Staff's position is that the Company's current pension cost recovery method should be maintained until a conclusion is reached in Docket UM 1633. Because that

[11] *See* Company's response to Staff Data Request No. 60, included as Exhibit Staff/1302, Bahr/14.

docket is still pending, Staff finds no basis for changing the Company's current pension cost recovery method.

Q. Was a settlement reached between the parties to the case regarding pension costs?

A. Yes, in conjunction with a group of other adjustments proposed by Staff, the parties reached a settlement regarding pension costs. Table B in Exhibit Staff/700, Gardner/5, shows which issues are included in the group, the total amount of the adjustment for the group of issues, and Staff's perspective of the allocation of the adjustment amount to each issue. Note that agreement was reached between the parties on the amount of the settlement, not necessarily on the allocation of the dollars to specific expenses. Staff supports the treatment of the pension issues in the partial stipulation as a reasonable resolution.

ISSUE 2, MEDICAL BENEFITS EXPENSE

Q. Please describe the Company's request regarding medical, dental, vision, and other benefits.

A. The Company has requested approximately $86.4 million in expenses relating to benefits.[12] This cost includes such forms of compensation as long term disability benefits, employee wellness program, and the pension plan. The expense includes costs for both bargaining (union) and non-bargaining (non-union) employees. Benefit plan premiums are typically shared between the Company and the employees. In its filing, the Company describes how its premium sharing structure has changed to allocate health care costs amongst employee groups more accurately, allowing for employees to choose between various plans tailored to suit the varying needs of employees.[13] Prior to the change, the Company generally shared costs with union employees at a ratio of 90/10 (employees pay 10 percent of premium costs and the Company pays 90 percent) and 85/15 for non-union employees.

Q. Please describe the analysis performed by Staff.

A. Staff reviewed the Company's responses to 22 Staff data requests as well as the Company's filing and supporting work papers. For its review, Staff first analyzed the overall historical trend in benefits costs and the Company's forecasted increase in premium amounts. Though medical benefits costs have been increasing in recent years, this trend is common among companies and supported by term sheets of the benefits providers, which indicate generally

[12] *See* PGE/500, Barnett-Jaramillo/19, at line 13.
[13] *See* PGE/500, Barnett-Jaramillo/20, at line 13

higher premiums and rising health care costs. Staff also compared actual annual costs to budgeted costs and found the Company has overbudgeted annually over the past four years by approximately two percent.

In addition to analyzing historical trends, Staff also compared the Company's costs to industry averages. Although the Company's sharing structure was altered since its last general rate case, the new structure is not expected to increase or decrease costs to the Company, but merely reallocate costs amongst employees.[14] Therefore, the Company's costs are virtually the same as though its 85/15 sharing structure for non-union employees were still employed. A survey found in the 2014 Kaiser Family Foundation publication indicates that the average sharing ratio in the industry is 82/18.

Staff typically relies on Kaiser Family Foundation research for industry health benefit trends and to date has yet to find a compelling reason to rely more heavily on other evidence. Regarding premium sharing, the survey states, "*Covered workers contribute on average 18% of the premium for single coverage … the same percentages as 2013.*"[15]

Staff calculated the difference between a sharing ratio of 85/15 and 82/18, which would result in a downward adjustment to the Company's proposed benefits non-union cost to align the Company's virtual sharing percentage with industry average.

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[14] *See* Company's response to Staff Data Request No. 293, included as Exhibit Staff/1302, Bahr/15.

[15] The 2014 Kaiser Family Foundation Report executive summary can be found online at http://files.kff.org/attachment/ehbs-2014-abstract-summary-of-findings. The premium sharing information used by Staff is found on page one, included as Exhibit Staff/1302, Bahr/16.

Staff typically proposes no adjustment to sharing between the Company and bargaining employees unless the sharing percentage is deemed unreasonable upon review. These rates are negotiated between the Company and the union, include a wide range of total compensation elements, and are difficult to adjust without upsetting the carefully negotiated compensation balance. In this case, Staff supported a reduction to union costs to reflect that annual costs have been approximately two percent less than budgeted costs over the past four years.

Finally, Staff reviewed the expenses for any unusual or unexpected costs. The Company's revenue requirement included an expense line item titled "Company Picnic" for $127,000. Based on Staff's experience working on these issues and a response to a Staff data request, Staff believes this expense is inappropriate to entirely pass on to customers, as it does not contribute to the provision of safe and reliable energy.[16]

Q. Did the Parties reach a resolution on the medical benefits expense issue?

A. Yes, this issue is included in the partial stipulation. The Parties agreed that non-union medical benefit expenses will be reduced by $577,000, and union medical benefit expenses will be reduced by $320,000. The biannual Company picnic expenses will be reduced by $95,000.

[16] *See* Company's response to Staff Data Request No. 397, included as Exhibit Staff/1302, Bahr/17.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff recommends the Commission adopt the Stipulation as agreed to by the Parties. With regard to pension costs, the expense originally proposed by the Company is reduced to reflect the Company's strong performance in consistently achieving higher than expected returns on its pension asset, and precedent is followed relating to the issue of the prepaid pension asset and the associated accumulated deferred tax benefit. Should the Commission decide to change the method of pension cost recovery through a decision in Docket No. UM 1633, the decision could be adopted in the Company's subsequent general rate case, or as otherwise directed by the Commission.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1301

Witness Qualification Statement

August 14, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Brian Bahr
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst
ADDRESS:	201 High Street SE., Suite 100 Salem OR 97301
EDUCATION:	Certificate of Public Management, Willamette University, Salem OR Bachelor of Science, Accountancy, Brigham Young University, Provo UT
EXPERIENCE:	Employed with the Oregon Public Utility Commission from March 2011 to present, currently serving as Senior Utility Analyst in the Rates, Finance, & Audit Section of the Energy Division. Employed by Modern Seouf Plastics in Alexandria, Egypt as a Managerial Intern from January 2010 to June 2010. Assisted in variety of duties including supervision of production facilities and staff, market analysis, budget forecasting, sales, and office administration. Employed by PricewaterhouseCoopers LLP in New York City as a Financial Assurance Associate from October 2007 to November 2009. Performed audits of various financial institutions, including investment banks, hedge funds, and insurance companies. Employed by TESRA, SA in Antofagasta, Chile as a Project Management Assistant from September 2005 to April 2006. Assisted in design process and implementation of rail road crossing and other civil engineering projects.

CASE: UE 294
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support of
Staff Testimony

<u>REDACTED</u>
August 14, 2015

March 24, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 232
Dated March 12, 2015

Request:

Please provide the forecasted prepaid pension asset balance and the associated accumulated deferred taxes through 2026.

Response:

See Attachment 232-A for the requested information. Please note that PGE only has long-term forecasted pension information covering the period of 2015 through 2024 and therefore is unable to provide information for the period of 2025 through 2026.

Attachment 232-A is confidential and subject to Protective Order No. 15-036.

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UE 294

Attachment 232-A

Confidential and subject to Protective Order No. 15-036

Provided in Electronic Format only

Prepaid Pension Asset and Associated Accumulated Deferred Tax
Forecast for 2015-2024

This page is confidential.

You must have signed the Protective Order No: 15-036

in Docket No. UE 294 to view this page.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2014 and 2013 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 527,004	$ 584,619	$ 108,249	$ 132,541
Service cost	15,757	19,045	1,844	4,144
Interest cost	26,224	23,896	5,226	5,216
Actuarial (gain)/loss	97,128	(78,234)	18,714	(18,017)
Plan change	—	277	—	(10,788)
Transfer of accrued vacation	—	—	437	1,189
Benefits paid	(31,439)	(22,599)	(6,481)	(6,036)
Benefit obligation as of end of year	$ 634,674	$ 527,004	$ 127,989	$ 108,249
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 481,502	$ 406,061	$ 29,732	$ 25,288
Actual return on plan assets	55,974	52,502	1,580	4,444
Employer contributions	32,000	44,263	—	—
Benefits paid	(30,165)	(21,324)	—	—
Fair value of plan assets as of end of year	$ 539,311	$ 481,502	$ 31,312	$ 29,732
Funded status	$ (95,363)	$ (45,502)	$ (96,677)	$ (78,517)
Unrecognized net actuarial loss	175,596	107,043	82,421	56,885
Unrecognized prior service cost	256	278	(10,379)	(707)
Prepaid (accrued) benefit cost	80,489	61,819	(24,635)	(22,339)
Additional liability	(175,852)	(107,321)	(72,042)	(56,178)
Accrued benefit liability	$ (95,363)	$ (45,502)	$ (96,677)	$ (78,517)
Accumulated pension benefit obligation	$ 551,615	$ 464,432	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 58,276	$ 52,384
For fully eligible employees			$ 31,843	$ 24,320
For other participants			$ 37,870	$ 31,545
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 166	$ 180	$ (6,747)	$ (7,472)
Unrecognized net actuarial loss	114,138	69,578	53,574	43,988
Total	114,304	69,758	46,827	36,516
Less regulatory asset	(106,484)	(64,925)	(46,759)	(37,116)
Accumulated other comprehensive loss (income) for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,820	$ 4,833	$ 68	$ (600)
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	4.21%	5.10%	4.16%	5.02%
Discount rate for annual expense	5.10%	4.15%	5.02%	4.15%
Expected long-term return on plan assets	6.60%	6.60%	6.40%	6.35%
Rate of compensation increase	4.87%	4.96%		
Medical cost trend pre-age 65—initial			7.00%	7.00%
Medical cost trend pre-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2021	2020
Medical cost trend post-age 65—initial			7.00%	7.50%
Medical cost trend post-age 65—ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2022	2021

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	$ 129	$ 155	$ 1,078	$ 1,518	$ 1,675	$ 1,747
Interest cost	17,682	16,249	17,598	3,521	3,215	4,166
Expected return on assets	(21,218)	(19,917)	(23,536)	(4,617)	(4,343)	(4,890)
Amortization of prior service cost (credit)	71	71	(46)	(1,393)	(1,457)	(1,438)
Recognized net actuarial loss	4,869	7,173	7,070	649	1,814	2,134
Curtailment gain	—	—	(1,023)	—	—	—
Amortization of net transition obligation	—	—	—	—	—	2,128
Net periodic benefit cost (credit), including amount capitalized	1,533	3,731	1,141	(322)	904	3,847
Less amount capitalized	388	727	937	(21)	164	910
Net periodic benefit cost (credit)	1,145	3,004	204	(301)	740	2,937
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	77,238	(60,173)	19,982	15,114	(30,461)	1,863
Prior service credit	—	—	—	—	—	(11,418)
Amortization of actuarial loss	(4,869)	(7,173)	(7,070)	(649)	(1,814)	(2,134)
Amortization of prior service (cost) credit	(71)	(71)	1,069	1,393	1,457	1,438
Amortization of net transition obligation	—	—	—	—	—	(2,128)
Total recognized in accumulated other comprehensive (income) loss	72,298	(67,417)	13,981	15,858	(30,818)	(12,379)
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss	$ 73,443	$ (64,413)	$ 14,185	$ 15,557	$ (30,078)	$ (9,442)

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are $7.1 million and $71,000, respectively. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2015 are $1.8 million and $1.4 million, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Discount rate	3.70%	4.53%	3.74%	4.48%
Expected return on plan assets	7.00%	7.00%	6.00%	6.00%
Rate of compensation increase	N/A	N/A	3.00%	3.00%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Discount rate	4.53%	3.65%	4.48%	3.67%
Expected return on plan assets	7.00%	7.00%	6.00%	6.00%
Rate of compensation increase	N/A	N/A	3.00%	4.00%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2014, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to

In 2015, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $15 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2014, relating to the postretirement benefit plan. The entire amount represents $15 thousand of amortization of prior service cost.

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law in December 2003 and established a prescription drug benefit under Medicare Part D, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage.

The following table summarizes the expected future benefit payments of the postretirement benefit plan and expected Medicare Part D subsidy receipts (in thousands of dollars):

	2015	2016	2017	2018	2019	2020-2024
Expected benefit payments	$ 3,970	$ 4,040	$ 4,090	$ 4,160	$ 4,210	$ 21,310
Expected Medicare Part D subsidy receipts	390	430	470	520	560	3,560

Plan Assumptions

The following table sets forth the weighted-average assumptions used at the end of each year to determine benefit obligations for all Idaho Power-sponsored pension and postretirement benefits plans:

	Pension Plan		SMSP		Postretirement Benefits	
	2014	2013	2014	2013	2014	2013
Discount rate	4.25%	5.20%	4.20%	5.10%	4.20%	5.15%
Rate of compensation increase[1]	4.30%	4.38%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.4%	6.8%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2014	12/31/2013	12/31/2014	12/31/2013	12/31/2014	12/31/2013

[1] The 2014 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.55% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in their fortieth year of service and beyond.

The following table sets forth the weighted-average assumptions used to determine net periodic benefit cost for all Idaho Power-sponsored pension and postretirement benefit plans:

	Pension Plan			SMSP			Postretirement Benefits		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Discount rate	5.20%	4.20%	4.90%	5.10%	4.15%	5.10%	5.15%	4.20%	5.05%
Expected long-term rate of return on assets	7.75%	7.75%	7.75%	—	—	—	7.25%	7.25%	7.25%
Rate of compensation increase	4.30%	4.38%	4.35%	4.50%	4.50%	4.50%	—	—	—
Medical trend rate	—	—	—	—	—	—	6.4%	6.8%	6.5%
Dental trend rate	—	—	—	—	—	—	5.0%	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.4 percent in 2014 and is assumed to decrease gradually to 5.1 percent by 2093. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2014 (in thousands of dollars):

	One-Percentage-Point	
	Increase	Decrease
Effect on total of cost components	$ 325	$ (241)
Effect on accumulated postretirement benefit obligation	3,426	(2,657)

Net periodic benefit costs are reduced by amounts capitalized to utility plant based on approximately 25% to 35% payroll overhead charge. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions. Net periodic pension cost less amounts charged to capital accounts and regulatory balancing accounts are expenses recognized in earnings.

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	4.71%	3.84%	4.51%	4.45%	3.56%	4.33%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	8.00%	n/a	n/a	n/a
Assumptions for year-end funded status:						
Weighted-average discount rate	3.85%	4.73%	3.85%	3.74%	4.45%	3.56%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	7.50%	n/a	n/a	n/a

The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2014 was 8.00% for pre-65 and 11.75% for post-65 populations. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.75% by 2022.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable from the Company. A one percentage point change in assumed health care cost trend rates would have the following effects:

In thousands	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	$ 62	$ (55)
Effect on the accumulated postretirement benefit obligation	1,260	(965)

The Company adopted a new set of mortality tables for its plans beginning with 2014. The tables were released in October 2014 by the Society of Actuaries' Retirement Plans Experience Committee and project a mortality improvement, thereby increasing benefit plan liabilities.

The following table provides information regarding employer contributions and benefit payments for the qualified pension plan, non-qualified pension plans, and other postretirement benefit plans for the years ended December 31, and estimated future contributions and payments:

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2013	$ 13,907	$ 1,895
2014	12,077	1,871
2015 (estimated)	16,567	1,848
Benefit Payments:		
2012	18,195	1,971
2013	18,855	1,895
2014	19,932	1,871
Estimated Future Benefit Payments:		
2015	20,315	1,848
2016	20,993	1,918
2017	21,784	1,955
2018	22,799	2,007
2019	24,162	2,075
2020-2024	137,839	10,412

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2014	2013	2012	2014	2013	2012
Benefit obligations as of December 31:						
Discount rate	4.00%	4.80%	4.05%	3.90%	4.90%	4.10%
Rate of compensation increase	2.75	3.00	3.00	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.80%	4.05%	4.90%	4.90%	4.10%	4.95%
Expected return on plan assets	7.50	7.50	7.50	7.50	7.50	7.50
Rate of compensation increase	3.00	3.00	3.50	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, PacifiCorp utilizes the asset allocation and return assumptions for each asset class based on forward-looking views of the financial markets and historical performance.

	2014	2013
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	8.00%	8.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025	2019

A one percentage-point change in assumed healthcare cost trend rates would have the following effects (in millions):

	Increase (Decrease)	
	One Percentage-Point Increase	One Percentage-Point Decrease
Increase (decrease) in:		
Total service and interest cost for the year ended December 31, 2014	$ 3	$ (2)
Other postretirement benefit obligation as of December 31, 2014	—	—

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $- million, respectively, during 2015. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006, as amended ("PPA"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA. PacifiCorp's funding policy for its other postretirement benefit plan is to generally contribute an amount equal to the net periodic benefit cost, subject to tax deductibility limitations and other considerations.

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2014	2013	2014	2013	2014	2013
Assumptions used:						
Discount rate for benefit obligation	4.02%	4.84%	3.07% - 4.10%	3.46% - 4.96%	4.02%	4.84%
Discount rate for benefit cost	4.84%	4.24%	3.46% - 4.96%	2.77% - 4.13%	4.84%	4.24%
Weighted average rate of compensation increase for benefit obligation	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Weighted average rate of compensation increase for benefit cost	3.65%	3.65%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	7.50%	7.50%	6.37%	6.46%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.50%	8.25%	6.46%	5.89%	N/A	N/A

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Service cost	$ 15	$ 17	$ 14	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	34	30	31	4	3	3	1	1	1
Expected return on plan assets	(39)	(40)	(41)	(2)	(1)	(1)	—	—	—
Amortization of prior service cost	—	—	—	1	1	1	—	—	—
Amortization of net actuarial loss	17	24	17	1	1	1	1	1	1
Net periodic benefit cost	$ 27	$ 31	$ 21	$ 6	$ 6	$ 6	$ 2	$ 2	$ 2

PGE estimates that $23 million will be amortized from AOCL into net periodic benefit cost in 2015 , consisting of a net actuarial loss of $20 million for pension benefits, $1 million for non-qualified benefits and $1 million for other postretirement benefits, and prior service cost of $1 million for other postretirement benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

April 27, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 390
Dated April 14, 2015

Request:

With regard to the Company's response to SDR No. 59, please provide the expected return on pension assets used to calculate the annual pension expense and the actual return on pension assets for each year from 2003 through 2014, inclusive.

Response:

The table below provides PGE's expected and actual return on pension plan assets covering the years 2003 through 2014.

Year	Expected Returns	Actual Returns
2014	7.50%	7.90%
2013	8.25%	18.39%
2012	8.25%	17.51%
2011	8.25%	3.68%
2010	8.5%	15.52%
2009	8.5%	26.17%
2008	9.0%	-27.94%
2007	9.0%	8.74%
2006	9.0%	13.71%
2005	9.0%	7.47%
2004	9.0%	11.13%
2003	9.0%	29.78%

III. PGE's Response to CUB

Q. CUB claims that PGE's prepaid pension asset has been built by negative expense and not by cash contributions[2]. Is this an accurate portrayal?

A. No. As discussed above, PGE has contributed $56 million into the prepaid pension asset since 2010 and $66 million since 2005. During this time period, PGE recognized one year of negative expense (-$2.4 million in 2008). So, while negative expense has played a role in the past, it represents a small portion of the current prepaid pension asset.

Q. Has CUB properly framed the discussion around PGE's market performance[3]?

A. No. CUB discusses the market performance of assets in the context of actual vs. projected rate of return. What is important when looking at the <u>performance</u> of a company's pension assets is how their returns measure up to <u>market</u> benchmark returns, not projections.

Q. What is the difference between market benchmark return and projected return?

A. A projected return or expected return on assets (EROA) is a long-term estimate that is actuarially determined and generally does not vary significantly from year to year. Its purpose is not to accurately forecast the real market returns for the year, but rather to provide an estimate of the expected average. This average helps smooth FAS 87 expense year to year with the understanding that while actual market returns can vary widely up and down each year, over time they will average near the forecasted projections.

Market benchmark returns are the actual returns that similar pension plans experienced during any given year. These have nothing to do with estimates or projections, only actual performance in the market at large.

Q. Why benchmark against market returns?

[2] CUB Exhibit 100, page 13
[3] CUB Exhibit 100, page 17-18

A. By looking at the market benchmarks you can have an accurate indication of plan performance and management.

Q. How do PGE's pension returns compare to the market benchmarks?

A. PGE's pension asset has consistently outperformed similarly sized pension plans for the last five years, performing in the top decile of funds over the five years ending September 30, 2013. Additionally, from 2000 through 2011, PGE's pension plan performance outpaced the average pension returns of the nation's largest companies (companies listed in the 2012 *Fortune* 1000) by an average of 1.2% annually. Since 1994, PGE has outperformed the market benchmark by 86 basis points on average. This is not the result of a "single year's showing of above average market performance[4]", it is the result of consistently beating the market benchmarks.

Q. CUB notes that PGE's plan lost value during 2008[5]. Was this unexpected?

A. No. Almost all pension plans lost value during the Great Recession. While PGE's pension assets lost value that year, it still outperformed the market benchmark by approximately 80 basis points[6].

Table 1

Year	Plan Assets	Actual Return	Market Benchmark	Difference	Improvement over Benchmark
	A	B	C	D = B – C	E = D * A
2008	$347,000,000	-26.66%	-27.48%	0.82%	$2,845,400

Q. Should one expect a pension plan to consistently perform better than the benchmark?

A. No. To perform better than the market benchmark during any year is difficult. The fact that PGE consistently beat the market benchmark is an indication of better than average plan management.

4 CUB Exhibit 100, page 18, line 11
5 CUB Exhibit 100, page 18
6 This can be translated into approximately $2.8 million improvement on market benchmark returns.

Q. What does this mean for PGE customers?

A. Market benchmark asset returns are what one might expect from a prudently run pension plan. As asset returns are one of the primary factors in determining both the level of FAS 87 expense and the amount of cash contributions needed to fund the pension plan, customers benefit from above benchmark returns through reduced FAS 87 expense and reduced cash contributions.

Q. Is PGE proposing "incentive regulation[7]"?

A. No. But as noted above, better than average market performance benefits customers. The current regulatory framework acts as a disincentive to manage the plan to achieve returns above market benchmarks.

Q. Explain how PGE is currently dis-incented.

A. The better PGE's pension asset performance is the lower its FAS 87 expense becomes for the year and the slower its prepaid pension asset winds down. As FAS 87 expense is the only thing used to set rates and the more FAS 87 expense that is incurred in the year, the more you can reduce the prepaid pension asset, realizing better than average returns can actually harm PGE's bottom line.

Q. Is PGE still asking for the opportunity to recover the costs associated with financing the prepaid pension asset?

A. Yes. PGE has incurred a cost as a direct result of funding the prepaid pension asset, while at the same time customers have received a benefit.

Q. Have PGE's pension investment fund managers "underperformed[8]"?

[7] CUB Exhibit 100, page 17
[8] CUB Exhibit 100, page 33, line 16

February 12, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Standard Data Request No. 060
Dated February 12, 2015

Request:

For FAS 87 and FAS 106, please provide the estimated effect on the Test Period Net periodic postretirement cost (income) if the discount rate is changed 25 basis points in both directions and expected rate of return is changed 25 basis points in both directions.

Response:

For FAS 87, the 2016 test year cost sensitivity to a +/- 25 basis point change in the discount rate is not symmetrical. For a 25 basis point increase in the discount rate, costs decrease approximately $2.2 million, while for a 25 basis point decline in the discount rate, costs increase approximately $2.3 million. The 2016 test year cost sensitivity to a +/- 25 basis point change in the expected rate of return is approximately $1.3 million.

For FAS 106, the 2016 test year cost sensitivity to a +/- 25 basis point change in the discount rate is not symmetrical. For a 25 basis point increase in the discount rate, costs decrease approximately $68,000, while for a 25 basis point decline in the discount rate, costs increase approximately $86,000. The 2016 test year cost sensitivity to a +/- 25 basis point change in the expected rate of return is not symmetrical. For a 25 basis point increase in the expected rate of return, costs decrease approximately $96,000, while for a 25 basis point decline in the expected rate of return, costs increase approximately $80,000.

April 1, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 293
Dated March 18, 2015

Request:

With regard to premium sharing as described on Exhibit PGE/500, Barnett-Jaramillo/24, please provide the annual dollar amount of the expected savings provided the Company by shifting from its previous sharing structure to a targeted sharing structure, and provide narrative explanation detailing how the expected savings are calculated.

Response:

As shown in confidential PGE Exhibit 502 and discussed in PGE Exhibit 500, page 25, PGE's employer paid portion of non-union health benefits are already below the industry average. As such, PGE did not develop or expect the targeted premium sharing structure change to produce additional savings or costs for PGE. As discussed in PGE Exhibit 500, pages 23 and 24, PGE changed from an overall 85/15 premium sharing structure for non-bargaining medical premiums to a targeted premium sharing structure in order to create a more balanced cost sharing structure for the employee share of medical premiums between PGE's high deductible health plans and more traditional plan offerings.

Staff/1302
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Employer Health Benefits

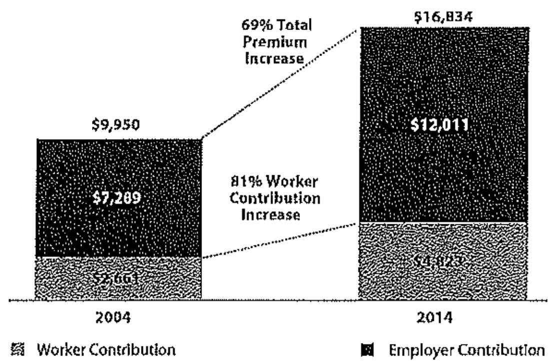
2014 Summary of Findings

Employer-sponsored insurance covers about 149 million nonelderly people.[1] To provide current information about employer-sponsored health benefits, the Kaiser Family Foundation (Kaiser) and the Health Research & Educational Trust (HRET) conduct an annual survey of private and nonfederal public employers with three or more workers. This is the sixteenth Kaiser/HRET survey and reflects employer-sponsored health benefits in 2014.

The key findings from the survey, conducted from January through May 2014, include a modest increase in the average premiums for family coverage (3%). Single coverage premiums are 2% higher than in 2013, but the difference is not statistically significant. Covered workers generally face similar premium contributions and cost-sharing requirements in 2014 as they did in 2013. The percentage of firms (55%) which offer health benefits to at least some of their employees and the percentage of workers covered at those firms (62%) are statistically unchanged from 2013. The percentage of covered workers enrolled in grandfathered health plans - those plans exempt from many provisions of the Affordable Care Act (ACA) - declined to 26% of covered workers from 36% in 2013. Perhaps in response to new provisions of the ACA, the average length of the waiting period decreased for those with a waiting period and the percentage with an out-of-pocket limit increased. Although employers continue to offer coverage to spouses, dependents and domestic partners, some employers are instituting incentives to influence workers' enrollment decisions, including nine percent of employers who attach restrictions for spouses' eligibility if they are offered coverage at another source, or nine percent of firms who provide additional compensation if employees do not enroll in health benefits.

EXHIBIT A

Average Annual Health Insurance Premiums and Worker Contributions for Family Coverage, 2004–2014



SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2004–2014.

HEALTH INSURANCE PREMIUMS AND WORKER CONTRIBUTIONS

In 2014, the average annual premiums for employer-sponsored health insurance are $6,025 for single coverage and $16,834 for family coverage. The average family premium rose 3% over the 2013 average premium. Single coverage premiums rose 2% in 2014 but are not statistically different than the 2013 average premium. During the same period, workers' wages increased 2.3% and inflation increased 2%. Over the last ten years, the average premium for family coverage has increased 69% (Exhibit A). Premiums have increased less quickly over the last five years (2009 to 2014), than the preceding five year period (2004 to 2009) (26% vs. 34%).

Average premiums for high-deductible health plans with a savings option (HDHP/SOs) are lower than the overall average for all plan types for both single and family coverage (Exhibit B), at $5,299 and $15,401, respectively. There are important differences in premiums by firm size: the average premium for family coverage is lower for covered workers in small firms (3–199 workers) than for workers in larger firms ($15,849 vs. $17,265).

Premiums vary significantly around the averages for single and family coverage, resulting from differences in benefits, cost sharing, covered populations, and geographical location. Twenty percent of covered workers are in plans with an annual total premium for family coverage of at least $20,201 (120% of the average family premium), and 20% of covered workers are in plans where the family premium is less than $13,467 (80% of the average family premium). The distribution is similar around the average single premium (Exhibit C).

Most often, employers require that workers make a contribution towards the cost of the premium. Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, the same percentages as 2013. Workers in small firms (3–199 workers) contribute a lower average percentage for single coverage compared to workers in larger firms (16% vs. 19%), but they contribute a higher average percentage for family coverage (35% vs. 27%). Workers in firms with a higher percentage of lower-wage workers (at least 35% of workers earn $23,000 or less) contribute higher percentages of the premium for single coverage (27% vs. 18%) and for family coverage (44% vs. 28%) than workers in firms with a smaller share of lower-wage workers.

As with total premiums, the share of the premium contributed by workers varies considerably among firms. For single coverage, 57% of covered workers are in plans that require them to make a contribution of less than or equal to a quarter of the total premium, 2% are in plans that require a contribution of more

April 29, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 397
Dated April 15, 2015

Request:

With regard to the file "2016 Corporate Support Summary" filed with the Company's workpapers for Exhibit PGE/600, specifically tab "Benefits by RC," please provide a narrative description or other support for including acct wo #7000002028 – Company Picnic (line 127) beginning in 2015 and 2016, given that it hadn't been included in 2014.

Response:

PGE's employee appreciation event demonstrates PGE's commitment to our employees, helps facilitate communication between employees in different areas of the company, and reinforces employees' perception of PGE as a family oriented employer. As a result, PGE expects higher employee morale and improved recruitment and retention efforts.

This event is held biennial, with the next two events scheduled to be held in the summers of 2015 and 2017 respectively. When building the 2016 forecast from PGE's 2015 budget, PGE inadvertently left this expense in the final 2016 test year forecast.

CASE: UE 294
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

STAFF TESTIMONY IN SUPPORT OF THE PARTIAL STIPULATION

August 14, 2015

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

A. My name is Judy Johnson. I am a Senior Economic Analyst with the Public Utility Commission of Oregon. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. I am writing testimony on three issues that I reviewed and are included in the multi-party settlement.

Q. Did you prepare an exhibit for this docket other than your qualifications exhibit?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

<u>Issue 1, Dues and Donations</u>

Q. What was PGE's filed position on Dues and Donations?

A. PGE reviewed its own Dues and Donations which are projected to be $3,502,892 for 2016 and removed $171,946 in its request for includable expenses.

Q. Did Staff agree with PGE's adjustment?

A. No. Staff reviewed PGE's proposed 2016 Dues and Donations and issued six data requests on dues and donations. After Staff reviewed the Company responses, Staff concluded that there was an additional amount that warranted removal.

Q. Did parties reach agreement on Dues and Donations?

A. Yes. The parties agreed that an additional $194,289 should be removed from PGE's requested expense level. The allowed Dues and Donations are reasonable and should be allowed by the Commission.

Issue 2, Construction Overheads

Q. What is Staff's concern regarding construction overheads?

A. Staff became interested in this issue while attending a PGE information workshop about construction overheads. During the workshop, PGE explained that many construction overheads could exceed 100 percent of the direct labor for the construction project. The overhead amount seemed excessive and so Staff followed up with 10 separate data requests. Staff's main concern regarding these overheads is that it might be reflective of high administrative and management costs and therefore should be scrutinized further. Alternatively, the overheads might be calculated differently than industry norms and thus may be reasonable given their method of calculation.

Q. Was this issue discussed and resolved in the settlement conference?

A. Yes. The Parties agreed PGE will obtain a third-party consultant to study the construction overheads accounting and methodology to better understand the calculation and whether it is a signal that PGE operations could operate more efficiently. The consultant will examine whether PGE can readily identify the sources of these expenses and the basis for their allocation.

Q. What role will Staff play in the selection of this outside expert?

A. The Company has agreed to consult with Staff and other parties when identifying an expert and when defining the scope of work.

Q. Is there a revenue requirement associated with this issue?

A. No. This is currently at the stage of fact-finding.

Issue 3, Coal Inventory

Q. Does Staff have an issue with PGE's coal inventory?

A. No. At the time OPUC Staff was preparing its settlement package, there were several outstanding data requests on the coal inventory issue. By the time of the second settlement meeting on May 29, 2015, the data requests concerning the coal inventory had been answered by the Company and Staff is satisfied that no revenue requirement adjustment is warranted.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: GEORGE R.COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

STAFF TESTIMONY IN SUPPORT OF THE PARTIAL STIPULATION

August 14, 2015

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

A. My name is George R. Compton. I am a Senior Economist, employed in the Energy - Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My qualifications statement is found in Exhibit Staff/301.

Q. What is the purpose of this testimony?

A. The purpose of my testimony is to support the partial stipulation on the subject of PGE's (or Company's) test year R&D budget.

Q. What is Staff's general orientation on this subject?

A. PGE joins with many other electric utilities across the country in sharing the sponsorship of the Electric Power Research Institute (EPRI), which performs research of interest to the electric utility industry at large. It is Staff's position that PGE should rely upon that industry-wide research rather than going out on its own. In sum, we prefer to see relatively modest R&D budgets for the Oregon utilities.

Q. What was the amount of the R&D budget proposed in PGE's general rate case application for the 2016 test period?

A. It was $3.1 million.

Q. How does that amount compare with actual R&D spending for the year 2014?

A. At $1.4 million, the 2014 actual amount is substantially below the year 2016's proposed amount.

Q. How did Staff approach this matter, and what were the initial findings?

A. Staff's starting position was to hold 2016 R&D spending to the same level as the 2014 actual amount. Staff issued four data requests on this topic, including a request that the Company prioritize its R&D budget as if the Company were limited to the 2014 actual amount. In their response to that latter request the Company identified a number of projects that were already ongoing at the end of 2015, and for which termination prior to their logical conclusions would be wasteful. Also, a number of the ongoing R&D projects are being conducted in partnership with other entities such as colleges and universities, which relieves the Company of a major portion of those projects' expenses. The Company also identified other projects, of which the principal subjects involved smart grid and energy storage applications that have a sufficiently high priority to warrant inclusion in a slimmed down 2016 R&D budget.

Q. Was a compromise reached regarding a final R&D budget?

A. Yes.

Q. What was the amount that the parties in this case settled upon?

A. It is $2 million, or $1.1 million less than appeared in the Company's original application. From Staff's perspective, this number accommodates the $1.4 million in "carry-over" projects from 2014 and 2015, and adds $0.6 million, which are targeted largely for smart-grid related investigations. For this reason, Staff supports the stipulation as reasonable.

Q. Does that conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

STAFF TESTIMONY IN SUPPORT OF THE PARTIAL STIPULATION

August 14, 2015

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

A. My name is Linnea Wittekind. I am a Senior Financial Analyst in the Energy – Rates, Finance and Audit Section. My business address is 201 High St SE, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1601.

Q. What issues were you responsible for in this docket?

A. I was assigned Director and Officer (D&O) Insurance and various Administrative and General (A&G) expenses.

Q. Are either of those issues included in the partial settlement reached among parties in this rate case?

A. Yes, both my adjustment to various A&G expenses and my adjustment to D&O Insurance were resolved and are included in the partial settlement. I would like to note that in analyzing various A&G expenses and D&O, I reviewed the Company's responses to ten multi-part Standard Data Requests and submitted nine additional follow up data requests.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the partial settlement reached amongst the parties on May 21 and May 29, 2015.

Q. Did you prepare an exhibit for this docket?

A. Yes, Exhibit Staff/1602.

Q. Briefly describe your analysis of the A&G issue.

A. PGE included in its UE 294 filing \$1.9 million in expenses for meals, entertainment and employee recognition identified in FERC Accounts 500 - 935. My analysis of these accounts identified 50 percent of these meals, entertainment and employee recognition expenses for removal from A&G, which is consistent with Commission practice.

Q. What would be the basis for removing 50 percent of these items from A&G?

A. Because the costs for meals, entertainment and employee recognition are discretionary and not required to provide safe and adequate service to customers, Staff's practice is to recommend a 50 / 50 sharing of expenses between customers and shareholders.

In Commission Order No. 09–020 (UE 197), the Commission adopted Staff's recommendation concerning meals and entertainment expenses and ordered the 50 percent sharing between customers and shareholders. The Commission stated on page 21:[1]

> We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders.

Q. Briefly describe your analysis related to D&O Insurance.

A. PGE included in its filed case \$[redacted] in D&O Insurance expense. This amount represents 100 percent of the cost of the first "layer" of insurance, and 50 percent of the remaining "layers". Exhibit PGE/600, Lobdell – Henderson –

[1] Docket No. UE 197, OPUC Order No. 09-020 at 21. An excerpt of the relevant rulings from that Order is included in Exhibit Staff/1602.

Tooman/12. My analysis is that 50 percent of the total cost of all layers of D&O insurance may be removed from A&G, which is also consistent with Commission practice.

Q. What would be the basis for removing 50 percent of D&O Insurance?

A. In PGE's general rate case filed in 2008, Docket UE 197, Staff proposed that customers and ratepayers share the cost of excess layers of D&O liability insurance. The Commission agreed the cost of D&O liability insurance should be split between ratepayers and shareholders. In fact, the Commission ordered that the Company absorb a greater amount of the cost of D&O insurance than proposed by Staff:

> We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost.[2]

Consistent with this ruling, Staff proposed an adjustment in Docket UE 283 removing 50 percent of the entire cost of D&O Insurance. Exhibit UE 283/Staff/500, Wittekind/3. Staff's adjustment was settled in the second partial stipulation in that docket, which was adopted by the Commission in Order No. 14-422.

Q. How have D&O Insurance and A&G been resolved in this docket?

A. Both issues are included in a larger settlement agreement. Staff's proposed adjustments to D&O Insurance and A&G expenses, along with adjustments to wages and salaries, pensions, escalation, and the fee free bankcard program and issues related to capital additions related to the Northfork Surface Collector

[2] OPUC Order No. 09-020 at 19-20 *See* Exhibit Staff/1602.

and Grassland Switchyard, Carty and coal inventory, were settled as a group for an \$8 million reduction in the Company's revenue requirement and a \$9 million reduction in rate base.

Q. Does this conclude your direct testimony?

A. Yes.

CASE: UE 294
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1601

Witness Qualification Statement

August 14, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Linnea Wittekind
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street, SE., Suite 100 Salem, OR 97301
EDUCATION:	B.S. Western Oregon University Major: Business with Focus in Accounting Minor: Entrepreneurship

EXPERIENCE:

Since November 2009, I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric and natural gas utilities. I have provided testimony in UE 215, UE 233, UG 221, UE 246, and UE 283 and have filed comments in LC 50 and numerous UP and UI dockets. I have also reviewed and analyzed a number of energy efficiency tariff filings. I've written several public meeting memos summarizing my analysis of the energy efficiency tariff filings. I have performed operational audits of NW Natural, Cascade Natural Gas, and Portland General Electric as well as assisted in an operational audit PacifiCorp. Recently I've completed an audit regarding gas accounting best practices.

Through the Public Utility Commission of Oregon, I am a member of the NARUC Staff Subcommittee on Accounting & Finance.

I've attended a number of trainings which include, The Basics through the Center for Public Utilities, New Mexico State University, Best Practices in an Era of Renewables and Reduced Emissions through EUCI as well as Benchmarking the Performance of Electric and Gas Distribution Utilities also through EUCI. I've also attended the Advanced Regulatory Studies Program through the Institute of Public Utilities at Michigan State University.

From July 2005 to November 2009, I worked as a Tax Auditor for the Oregon Department of Revenue. In enforcement of tax laws, rules and regulations, I performed income tax audits of individual tax payers and small businesses. Additionally I prepared cost analysis of tax credits and measures. I also represented the department before the Oregon Tax Court for tax deficiency appeals.

CASE: UE 294
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1602

Exhibits in Support of
Staff Testimony

August 14, 2015

as a shareholder cost. D&O insurance protects PGE senior management in the event that they are sued, whether by customers, stockholders, or others in conjunction with the performance of their Company duties. According to Staff, "[c]ustomers, who have no say in electing or appointing PGE's Directors or Officers, should not be held financially responsible in providing 100 percent of insurance coverage against business decisions or improprieties by management which results in lawsuits."[74] Third, Staff proposes to apply a utility allocation percentage to the overall insurance premiums to allocate the cost between the utility and non-utility aspects of PGE's operations.[75] Finally, Staff proposes a $1.75 million adjustment to PGE's Uninsured Losses based on escalating the five-year historical average by inflation.[76]

PGE contends that D&O liability insurance is a normal cost of doing business, and the entire cost should be included in its revenue requirement. PGE also includes updates to its policies in rebuttal testimony and claims Staff did not properly consider certain policies. PGE further noted that flat insurance rates can still result in increased premiums when property values increase. The Company proposed that the utility allocation factor adjustment should be applied only to a limited number of specific categories.[77]

Resolution

We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost. We also adopt Staff's proposal to hold premiums steady for 2009 property and liability insurance and apply the utility allocation percentage to overall policy premiums. In addition, we adopt Staff's adjustment to Uninsured Losses. PGE's 2009 revenue requirement is therefore reduced by $3.717 million.

h. Miscellaneous Expenses

These expenses consist primarily of costs for catering, gifts, promotional items, and civic activities, including lunch meetings and gifts to employees for overtime work or as retirement gifts, sympathy gifts to employees' families, holiday activities and "team-building days for employees."

Staff proposes that 50 percent of the meal and entertainment expenses, office refreshments and catering, gifts of flowers, and awards be disallowed. In Staff's view, these expenses should be shared equally between ratepayers and shareholders. This approach somewhat mirrors the policy associated with bonuses and the handling of meal and entertainment expenses for income tax purposes.[78]

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[74] *See* Staff/900, Ball/11.
[75] *Id.* at 15.
[76] Staff/300, Ball-Dougherty/11; Staff/900, Ball/14; Staff/901, Ball/4.
[77] PGE Opening Brief at 33-36 and testimony cited therein.
[78] Staff Opening Brief, citing Staff/300, Ball-Dougherty/13-15.

Staff also proposes removing 100 percent of civic activities recorded in Administrative & General (A&G) accounts, noting "the Commission has not previously allowed regulated utilities to recover contributions to charities, community affairs, and economic development organizations through rates charged for regulated services. . . . In addition, Commission policy does not require customers to support causes in which they do not believe."[79]

PGE asserts that these discretionary costs are appropriately included in rates, because these miscellaneous expenses create a business culture that allows the utility to attract and retain qualified workers.[80]

Resolution

We agree with Staff that the costs for food and gifts are discretionary and should be shared equally by ratepayers and shareholders. We also adopt Staff's recommendation with respect to contributions to charities, community affairs, and economic development organizations. PGE provides no rationale to change our existing policies, and we conclude that all contributions to charities, community affairs, and economic development organizations should be disallowed. PGE's 2009 revenue requirement is reduced by $710,000 to reflect the disallowance of these expenses.

We also acknowledge PGE's removal of Directors' Compensation and Officer Vehicles from the proposed 2009 test-year budget. The total revenue-requirement reduction for miscellaneous expenses is $1.18 million.

i. Senate Bill 408 Ratio Adjustment

Senate Bill 408 (SB 408) requires the Commission to establish certain ratios in general ratemaking proceedings, which will be used to determine the amounts of "taxes collected" from customers for the purpose of the SB 408 true-up of "taxes paid" to "taxes collected." PGE believes that, in setting the tax rate and margin ratios here for SB 408 purposes, the Commission should consider the impact of costs that have been disallowed. PGE explains that, "[t]o do otherwise would effectively allow customers to receive tax benefits from utility costs for which customers are not responsible."[81]

Staff opposes PGE's proposal as an attempt to insulate its shareholders from sharing the tax benefit of disallowed expenses with ratepayers when truing up the amount of taxes collected. Staff believes PGE's request is inconsistent with the terms of SB 408, as well as Commission rules implementing the bill.[82] According to Staff, the Commission indirectly addressed this issue when it declined PGE's request for a deferral

[79] *Id.*, citing Staff/300, Ball-Dougherty/15.
[80] PGE Opening Brief at 37, citing PGE/2700, Piro-Tooman/12.
[81] PGE/2300, Tooman-Tinker/24.
[82] *See* ORS 757.268 and OAR 860-022-0041.

CASE: UE 294
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1700

STAFF TESTIMONY IN SUPPORT OF THE PARTIAL STIPULATION

August 14, 2015

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

A. My name is Jorge Ordonez. I am employed by the Public Utility Commission of Oregon (OPUC) as a Senior Economist in the Energy Resources and Planning Division. My business address is 201 High St. SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualifications Statement is found in Exhibit Staff/901, Ordonez /1 in this proceeding.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the partial stipulation reached by Staff and Parties, specifically regarding two capital additions: Portland General Electric's (PGE's) decision to construct the Carty Generation Station (Carty), including the Grassland Switchyard (Grassland), and the Clackamas PME – Surface Collector C project (Clackamas Surface Collector). Staff recommends that the Commission approve the partial stipulation.

Q. Did you prepare an exhibit for this docket other than your qualifications exhibit?

A. Yes. I have prepared Exhibit Staff/1701 consisting of six pages, Confidential Exhibit Staff/1702 consisting of 48 pages, and Exhibit Staff/1703 consisting of two pages.

TESTIMONY ORGANIZATION

I. Carty and Grassland

II. Clackamas Surface Collector

I. CARTY AND GRASSLAND

PGE's Request

Q. What was the Company's request in its Direct Testimony?

A. In several parts of the Company's Direct Testimony,[1] PGE requested that the OPUC authorize tariffs to include in rates the costs of Carty when placed in service.

Q. Please provide a brief description of Carty.

A. Carty is adjacent to the currently operating Boardman Plant in Boardman, Oregon. It is a G-class combined cycle combustion turbine (CCCT) with a capacity of 441 MW that is designed to provide base load capacity.[2, 3] The capital cost of Carty is approximately $488 million.[4] Including the capital cost of Grassland, which will be described later in my testimony, of approximately $25 million, the Carty and Grassland capital cost total approximately $514 million.

Q. When does PGE expect to place Carty in service?

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[1] PGE asked the OPUC to authorize the tariffs in the following parts of its Direct Testimony:

- On page 2 of PGE's Executive Summary, filed concurrently with its Direct Testimony, the Company represented: "*In accordance with past Commission practice, PGE requests that Carty be incorporated into customer prices when it begins service to customers.*"
- On page 4 of *Id.*, the Company represented: "*"PGE seeks a schedule in this docket that will allow for a Commission order by mid-December and revised tariff schedules implemented on January 1, 2016, with an additional price change implemented when Carty begins service to customers."*
- On page 5 of *Id.*, the Company represented: "*PGE's request with respect to the price change when Carty comes online is consistent with past Commission practice. As has been done in previous dockets, when the plant is online, PGE will provide an attestation of a PGE officer verifying that the plant is in operation and available for service to customers. PGE requests that after the filing of such an attestation, prices including the costs of the plant become effective.*"
- In Exhibit PGE/200, Tooman-Brown/2, lines 3-6, the Company represented: "*PGE requests that the Public Utility Commission of Oregon (OPUC) authorize tariffs to collect the annualized amount beginning with the in-service date of Carty. We currently expect Carty to be in service in the second quarter of 2016.*"

[2] See Exhibit PGE/300, Pope - Lobdell/3, line 3.

[3] Base load capacity is the generating equipment normally operated to serve loads on an around-the-clock basis.

[4] See Exhibit PGE/300, Pope - Lobdell/12, line 5.

A. In its Direct Testimony, the Company represented that it anticipates the in-service date of Carty to be in the second quarter of 2016.[5]

Q. Why does the Company believe its request for Carty is reasonable?

A. Based on PGE's Direct Testimony, Staff has identified three components of the Company's claim of reasonableness:

1. The Company's request is consistent with past Commission practice,
2. Carty is the result of PGE's integrated resource plan (IRP) process, and
3. Carty is the result of PGE's request for proposal (RFP) process.

Q. Please explain the first component of the Company's claim of reasonableness (i.e., that the Company's request "is consistent with past Commission practice").

A. In its Direct Testimony, the Company represented that "PGE's request with respect to the price change when Carty comes online is consistent with past Commission practice. As has been done in previous dockets, when the plant is online, PGE will provide an attestation of a PGE officer verifying that the plant is in operation and available for service to customers. PGE requests that after the filing of such an attestation, prices including the costs of the plant become effective."[6]

Q. Please explain the second component of the Company's claim of reasonableness (i.e., Carty is the result of PGE's IRP process).

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[5] See Exhibit PGE/300, Pope - Lobdell/15, line 3-4.
[6] See page 5 of PGE's Executive Summary, which was filed concurrently with the Company's Direct Testimony.

A. In its 2009 IRP, PGE identified a shortfall in its annual average energy need, which resulted in PGE's action plan to acquire additional energy resources by 2015. A baseload resource, such as a high-efficiency CCCT, comprised a portion of the energy resource additions considered. The Commission acknowledged the 2009 IRP action plan in Order No. 10-457 of Docket No. LC 48.[7] The Company also described how the updates to its 2009 IRP continued to support the need for the base load resource.[8]

Q. Please explain the third component of the Company's claim of reasonableness (i.e., Carty is the result of PGE's RFP process).

A. In its Direct Testimony, PGE represented that "Carty was chosen through a robust [RFP] process in accordance with the Commission's rules and guidelines [as well as] [i]t was identified as the least cost/least risk resource to fill the need"[9] of base load capacity.

Historical Treatment of this Kind of Request

Q. What is the latest ruling regarding this kind of request?

A. In Order No. 12-493 of Docket No. UE 246 (PacifiCorp 2012 Rate Case), the OPUC granted PacifiCorp a tariff rider to recover the costs of the M2O Transmission Line.[10] Regarding this docket, it should be noted that:

- The PacifiCorp 2012 Rate Case was filed on March 1, 2012, with a 2013 test period;

[7] See Exhibit PGE/300, Pope - Lobdell/2, lines 2-9.
[8] See Exhibit PGE/300, Pope - Lobdell/2-3.
[9] See page 2 of PGE's Executive Summary filed concurrently with its Direct Testimony.
[10] See pages five to eight of Order No. 12-493 of Docket No. UE 246 at http://apps.puc.state.or.us/orders/2012ords/12-493.pdf

- At the time of filing, PacifiCorp anticipated the M2O Transmission Line to be placed in service in May 2013;
- Parties in the PacifiCorp 2012 Rate Case stipulated that the investment was prudent, but disagreed on whether the Commission should grant PacifiCorp the tariff rider; and
- In Order No. 12-493, the OPUC granted PacifiCorp the tariff rider, because the OPUC had previously acknowledged the transmission line as part of the utility's IRP process and other parties had stipulated to the prudence of the investment with the conditions.

Analysis

Prudence of the Decision to Pursue Carty

Q. What standard does the Commission use to determine whether an investment is prudent?

A. In Docket No. UE 246, the Commission provides this example of the prudence standard:

> "A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company."[11]

[11] See page 25 of Order No. 12-493 in Docket No. UE 246 at http://apps.puc.state.or.us/orders/2012ords/12-493.pdf

Q. Has Staff analyzed the prudence of the Company's pursuit of Carty?

A. Yes. Staff has analyzed the prudence of the Company's pursuit of Carty from two perspectives: 1) the consistency of Carty with previous IRPs and RFPs, and 2) the prudence of Carty as of the date when the Company decided to proceed with the project.

Consistency of Carty with Previous IRPs and RFPs

Q. Please explain the first perspective (i.e., the consistency of Carty with previous IRPs and RFPs).

A. Staff's analysis, described below, is the result of its review of multiple data requests (DRs), PGE's 2009 IRP, updates to PGE's 2009 IRP, and PGE's 2012 RFP.

Q. Please explain Carty's consistency with PGE's 2009 IRP.

A. PGE's 2009 IRP, filed on November 5, 2009, in Docket No. LC 48,[12] identified the need for approximately 873 average megawatts (aMW) of resources in 2015.[13] The need would be partially[14] covered with approximately 400 aMW of baseload generation from new, high-efficient natural gas generation as represented in Action Item 4 of the IRP.[15] In Order No. 10-457 in Docket No.

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[12] See http://edocs.puc.state.or.us/efdocs/HAA/lc48haa151359.pdf.
[13] See page 4 of PGE 2009 IRP at http://edocs.puc.state.or.us/efdocs/HAA/lc48haa151359.pdf.
[14] To cover the anticipated deficit, in addition of the approximately 400 aMW to be provided by new, high-efficiency natural gas generation, the PGE action plan included other resources such as energy savings (214 aMW), Tuccannor River Wind Farm (122 aMW), short- and mid-term market purchases (100 aMW), the Boardman lease contract (72 aMW), and existing contract renewals (66 aMW). For more details, see page 320 of the PGE 2009 IRP at http://edocs.puc.state.or.us/efdocs/HAA/lc48haa151359.pdf.
[15] See page 7 of the PGE 2009 IRP at http://edocs.puc.state.or.us/efdocs/HAA/lc48haa151359.pdf.

LC48, entered on November 23, 2010, the Commission acknowledged PGE's 2009 IRP.[16]

The two top-performing portfolios (i.e., Green with the on-peak energy target and Boardman through 2020), both of which included Carty, provided to PGE the best combination of cost and risk (Best Cost/Risk).[17]

Q. Please explain Carty's consistency with the Company's updates to PGE's 2009 IRP.

A. PGE filed two updates to its 2009 IRP: the 2011 Update filed on November 23, 2011,[18] and the 2012 Update filed on November 21, 2012.[19] PGE's 2011 Update recognized that 2016 was a more likely start year for new baseload resource additions due to the extended regulatory process and RFP schedule. The 2011 Update identified a remaining[20] energy deficit for 2015 of approximately 682 aMW.[21] The 2011 Update also identified a remaining energy deficit for 2016 of approximately 770 aMW.[22] PGE's 2012 Update identified an energy deficit for 2016 of approximately 649 aMW.[23]

Q. Please explain Carty's consistency with PGE's 2012 RFP.

A. PGE's 2012 RFP in Docket No. UM 1535 resulted in the selection of Carty as the lowest-cost, least-risk bid. The Company described how the RFP process

[16] See page 30 of the referenced order at http://apps.puc.state.or.us/orders/2010ords/10-457.pdf.
[17] See page 84 of PGE's 2009 IRP Addendum at http://edocs.puc.state.or.us/efdocs/HAQ/lc48haq12127.pdf.
[18] See http://edocs.puc.state.or.us/efdocs/HAD/lc48had152312.pdf.
[19] See http://edocs.puc.state.or.us/efdocs/HAH/lc48hah112927.pdf.
[20] By using the word "remaining," Staff emphasizes that there is still a need for 682 aMW compared to the Company's initial 2009 IRP in which the need for 2015 was 873 aMW.
[21] See page 9 of PGE's 2011 Update at http://edocs.puc.state.or.us/efdocs/HAD/lc48had152312.pdf.
[22] See page 10 of PGE's 2011 Update at http://edocs.puc.state.or.us/efdocs/HAD/lc48had152312.pdf.
[23] See page 10 of PGE's 2012 Update at http://edocs.puc.state.or.us/efdocs/HAH/lc48hah112927.pdf.

resulted in selecting the bid submitted by Abengoa S.A. instead of PGE's benchmark resource bid.[24] In the Final Report of the Independent Evaluator (IE) of the 2012 RFP process (issued on January 30, 2013), the IE concluded that it "believes [the] RFP was conducted in a fair and unbiased manner and that the Final Short List accurately identified the Bids with the most value for PGE customers."[25]

Prudence of Carty as of the Date When the Company Decided to Proceed with the Project

Q. Please explain the second perspective (i.e., the prudence of Carty as of the date when the Company decided to proceed with the project).

A. Staff's aim was to determine whether the decision to proceed with the project was prudent as of or close to June 3, 2013, which was when the Company filed Form 8-K with the Securities and Exchange Commission (SEC), included in Exhibit Staff/1701, Ordonez/1-6, announcing that it had entered into an agreement with Abengoa S.A.[26] for the construction of Carty.[27]

Staff's analysis focused on two aspects: 1) whether the need for the base load was still present, and, if so, 2) whether that need could have been met with resources other than Carty.

Q. Please explain Staff's findings under its first item of consideration (i.e., whether the need for base load was still present).

[24] See Exhibit PGE/300, Pope - Lobdell/5.
[25] See UM Docket No. 1535, Final Report (January 30, 2013) at page 2, available at http://edocs.puc.state.or.us/efdocs/HAH/um1535hah162426.pdf.
[26] PGE entered into the agreement with Abeinsa Abener Teyma, an affiliate of the international developer and contractor Abengoa S.A.
[27] See http://investors.portlandgeneral.com/secfiling.cfm?filingID=784977-13-35.

A. As shown in Table 1 below, as of November 21, 2012, approximately six months before June 3, 2013, the Company still needed approximately 649 aMW in 2016. This need was assumed to be covered by 406 aMW from Carty and 286 aMW from other resources, which in the aggregate would provide 692 aMW. Going forward, as shown in Figure 1 below, with the contribution of Carty's 400 aMW, the Company would maintain a positive balance until approximately 2018, with a deficit starting in 2019.

Table 1[28]

Table 1-2: Comparison of PGE's Energy Action Plan in 2016

Annual Energy Action Plan for 2016	2009 IRP MWa	2012 IRP Update MWa	2012 IRP Update Change MWa
PGE Load Before EE Savings [1]	2,815	2,680	(135)
Remove 5-year Opt-Outs	(28)	(195)	(166)
Existing PGE & Contract Resources	(1,834)	(1,836)	2
PGE Resource Target	952	649	(303)
Resource Actions			
Thermal:			
CCCT	406	406	-
Combined Heat & Power	2	2	-
Renewable:			
ETO Energy Savings Target [1]	247	183	(64)
Existing Contract Renewal	66	-	(66)
2012 RFP Renewables	122	101	(21)
To Hedge Load Variability:			
Short and Mid-Term Market Purchases	100	-	(100)
Total Incremental Resources	943	692	(251)
Energy (Deficit)/Surplus	(9)	43	52
Total Resource Actions	952	649	

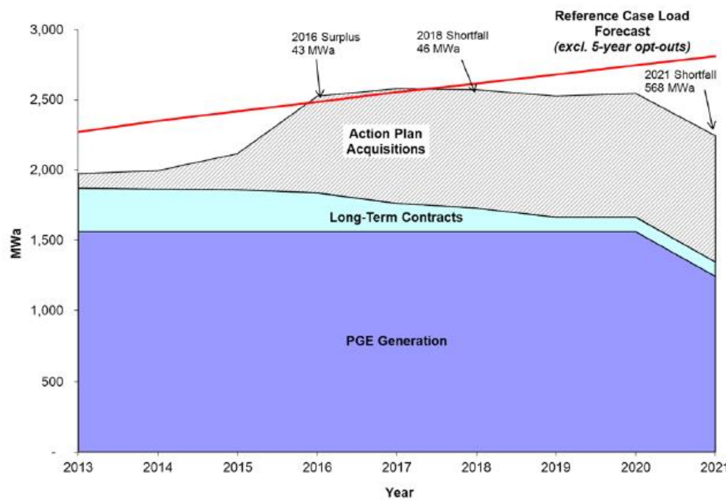
Output of Carty

Resource Need

Figure 1[29]

[28] Source: Page 10 of PGE's 2012 Update to its 2009 IRP at http://edocs.puc.state.or.us/efdocs/HAH/lc48hah112927.pdf.
[29] Source: Page 11 of PGE's 2012 Update to its 2009 IRP at http://edocs.puc.state.or.us/efdocs/HAH/lc48hah112927.pdf.

Figure 1-1: Energy Load Resources Balance to 2021 after Action Plan Acquisitions



Q. Was the need for base load substantiated on any other date?

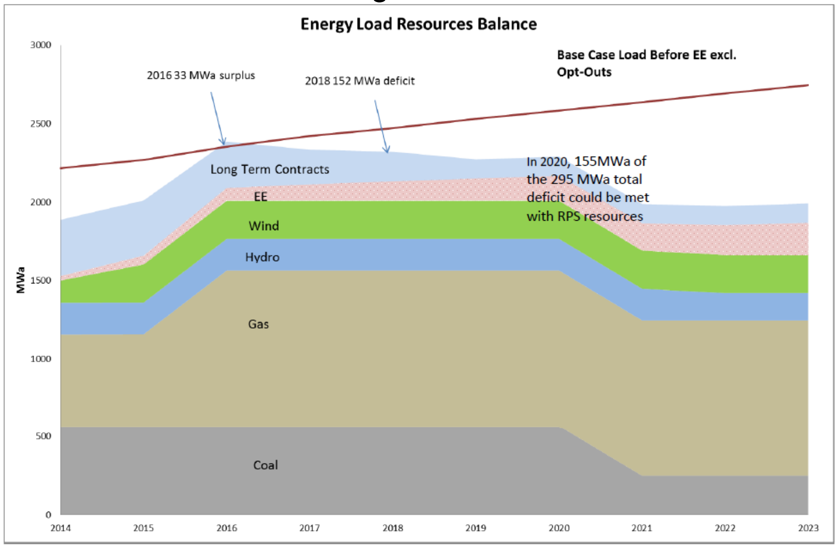
A. Yes. On April 3, 2013, the Company updated its load resource balance as shown in Figure 2 below.

With the contribution of Carty's approximately 400 aMW, the surplus for 2016 was approximately 33 aMW, slightly lower than the surplus of 43 aMW for 2016 from the November 2012 load resource balance. Also, the deficit for subsequent years was notably increased. For example, for 2018, the deficit of 46 aMW was increased to 152 aMW. This demonstrates the importance of Carty's output of approximately 400 aMW to meet the Company's need.

Additionally, in the Addendum to the Final Report of the IE (issued on February 14, 2013), the IE found the "baseload, natural gas-fired capacity to be consistent with the acknowledge[d] IRP needs and those needs did not change enough to justify redesigning the RFP categories." [30]

[30] See the IE Addendum to the Final Report, page 4, Docket No. UM 1535, available at http://edocs.puc.state.or.us/efdocs/HAH/um1535hah162717.pdf.

Figure 2[31]



Q. Now that you have explained the "need" aspect of Carty, please explain Staff's findings with respect to whether such "need" could have been met with resources other than Carty.

A. Staff has investigated other means by which the "need" for Carty could have been fulfilled, such as: relying on the market (i.e., Short- and Mid-Term Market Purchases or Market Purchases), power purchase agreements, ownership of existing facilities, and engineering, procurement, and construction (EPC) contracts.

Q. Please explain the first option for meeting the need with resources other than Carty (i.e., Market Purchases).

A. Market Purchases are spot-market purchases made in the short- and mid-term. Throughout PGE's IRP process from 2009 through 2012, PGE assumed 100 aMW of Market Purchases.[32]

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[31] Source: Page 39 of PGE's 1st Stakeholder Presentation & Discussion, dated April 3, 2013, in preparation for the Company's 2013 IRP at https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/irp_2013.pdf.

Q. Why did the company not replace the 400 aMW with market purchases?

A. First, the 100 aMW assumption is consistent with the roughly 100 aMW in Market Purchases made by the Company in the four years prior to June 3, 2013 (i.e., 2009 through 2012). Staff believes that this reliance on the market would have been imprudent, because in the IRP process, the Company analyzed a possible aggressive “go-short” strategy portfolio, which was embodied by the Market Portfolio.[33] The Market Portfolio consisted of replacing the approximately 400 aMW to be provided by Carty with Market Purchases. The Market Portfolio did not comply with reliability standards, because it was the worst-performing strategy with respect to tailvar unserved energy (Tailvar UE).

Q. Please explain the other options for meeting the need with resources other than Carty (i.e., power purchase agreements, ownership of existing facilities, and EPC contracts).

A. PGE’s 2012 RFP requested the products listed in Table 2 below to cover the 400-aMW need. As shown in confidential appendices D and E of the IE’s Final Report of the 2012 RFP process (issued on January 30, 2013), included in Confidential Exhibit Staff/1702, Ordonez/1-48, the initial short list and final short list included multiple bids involving the aforementioned options.

Table 2
Summary of Requested Base Load Natural Gas Products

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[32] For example, for PGE’s 2009 IRP, see page 322 of PGE’s IRP 2009 at http://edocs.puc.state.or.us/efdocs/HAA/lc48haa151359.pdf.

[33] The Market Portfolio was described on page 226 of PGE’s 2009 IRP at http://edocs.puc.state.or.us/efdocs/HAA/lc48haa151359.pdf and on page 20 of PGE’s Addendum to its 2009 IRP at http://edocs.puc.state.or.us/efdocs/HAQ/lc48haq12127.pdf.

Product	Block		Start Date			Term	
	Min	Max	No earlier than	Preferred	No later than	Min	Target
Power Purchase Agreement	300 MW	500 MW	2014	By end of 2015	2017	10 years	20+ years
Ownership[2]	300 MW	500 MW	2014	By end of 2015	2017	NA	NA
EPC	See Baseload Energy Specification in Appendix S		2014	By end of 2015	2017	NA	NA

The RFP process resulted in selection of the bid submitted by Abengoa S.A. instead of PGE's benchmark resource bid.[34] In the Final Report of the IE of the 2012 RFP process, the IE concluded that it "believes [the] RFP was conducted in a fair and unbiased manner and that the Final Short List accurately identified the Bids with the most value for PGE customers." [35]

Finally, in the Addendum to the Final Report of the IE (issued on February 14, 2013), the IE found that "the final short list selections provided a reasonable mix of products to meet the identified system need." [36]

Q. What is Staff's conclusion regarding the prudence of Carty?

A. Staff finds that, based on all the circumstances at the time, PGE's decision to proceed with Carty was prudent.

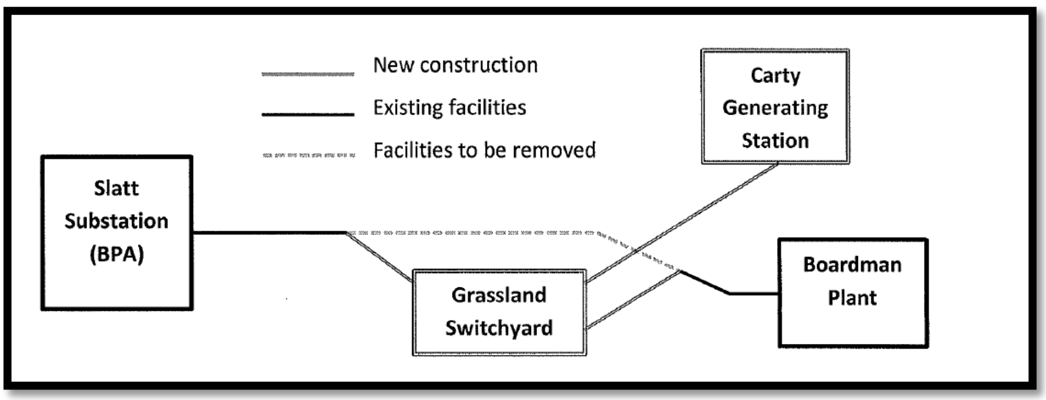
Q. The stated purpose of your testimony included a reference to Grassland. What is Grassland?

A. As depicted in Figure 2 below, Grassland is a switchyard that will be built to integrate Carty into the existing Boardman-Slatt transmission line.

[34] See Exhibit PGE/300, Pope - Lobdell/5.
[35] See Docket UM 1535, Final Report at page 2, available at http://edocs.puc.state.or.us/efdocs/HAH/um1535hah162426.pdf.
[36] See UM Docket No. 1535, Addendum to Final Report (February 14, 2013) at 4, available at http://edocs.puc.state.or.us/efdocs/HAH/um1535hah162717.pdf.

Abengoa S.A.[37] will remove a portion of the existing facilities that are transferring energy between Boardman and Slatt as identified by the dashed line in Figure 2. Carty, along with Boardman, will be connected to Grassland, and a single transmission line will continue to run to Slatt. Grassland will allow one plant to continue to deliver energy even if the other plant is out of service.[38] In its Direct Testimony, PGE anticipated that Grassland would be in service in June 2015 and requested to include the costs of this switchyard in rates beginning on January 1, 2016.[39]

Figure 2[40]



Q. Did Staff examine the Grassland project?

A. Yes. Staff issued two data requests concerning this project.

Q. What were Staff's findings?

---

[37] PGE entered into the agreement with Abeinsa Abener Teyma, an affiliate of the international developer and contractor Abengoa S.A.

[38] See Exhibit UE 294/PGE/300, Pope – Lobdell/9-10, lines 19-20 (page 9) and lines 1-3 (page 10).

[39] Grassland was included as a capital addition in PGE's general rate case. The general rate case requested new rates to enter into effect in January 1, 2016. See page 4 of PGE's Executive Summary, filed concurrently with its Direct Testimony, wherein the Company represented: "PGE seeks a schedule in this docket that will allow for a Commission order by mid-December and revised tariff schedules implemented on January 1, 2016, with an additional price change implemented when Carty begins service to customers."

[40] Source: Exhibit UE 294/PGE/300, Pope – Lobdell/10.

A. Staff finds this project is also prudent and necessary to operation of Carty. In fact, if it were not for the construction of Carty, Grassland would have not been built. This was corroborated by the Company in its response to Staff Data Request number 433, included in Exhibit Staff/1703, Ordonez/1-2.

Q. How has the issue of Carty, including the Grassland Switchyard been addressed by the parties?

A. In the partial stipulation, the stipulating parties agree that the decision to construct Carty was prudent, and the tariff rider requested by PGE should be approved to reflect the costs and benefits of the plant when it is placed in service, with certain conditions.

The first condition is that for purposes of this docket, the gross plant for Carty, including Grassland, will be $514 million. If actual capital costs are lower than $514 million, PGE has agreed to refund the 2016 revenue requirement difference resulting from the lower capital costs, with interest at its overall authorized cost of capital, beginning January 1, 2017. If Carty capital costs are higher, PGE may not recover those costs through the Carty tariff rider, but PGE will not be bound to the original $514 million estimate in subsequent rate proceedings. If PGE seeks to recover any additional amounts in a subsequent general rate filing, PGE must demonstrate the prudence of the additional costs. The second condition is that PGE will file an attestation by a corporate officer when the Carty plant is placed in service. If Carty is not completed and in service by July 31, 2016, PGE will need to file a new ratemaking request before including Carty costs in rates, inclusive of Grassland.

Q. What are Staff's findings and recommendation with respect to Carty?

A. Staff finds that PGE's decision to construct Carty and Grassland was prudent and recommends that the Commission adopt the stipulation reached by Staff and Parties for granting PGE the Carty tariff rider when Carty is placed in service.

II. CLACKAMAS SURFACE COLLECTOR

Q. Please provide a brief description of the Clackamas Surface Collector

A. This project consists in building a floating surface collector (collector) on the Clackamas River will boost the survival rate of fish traveling downstream from the North Fork Dam. The collector is 147 feet long and 60 feet wide and is being built on a steel barge. When complete, all but three feet of the 26 foot depth of the collector will be submerged. A series of engineered pumps and screens will create an attractant flow of water to lure fish inside.

Q. How has the issue of the Clackamas Surface Collector been addressed by the parties?

A. In the partial stipulation, the stipulating parties agree that when the North Fork Surface Collector project is placed into service, PGE will file an attestation from an officer attesting that the plant has been placed into service. If the plant is not placed into service by December 31, 2015, the project costs will be removed from the test-year rate base. Project costs included in test-year rate base will be the lesser of actual project costs or $53.8 million. If North Fork capital costs are higher than that amount, PGE will not be bound to its original $53.8 million estimate in subsequent general rate proceedings. If PGE seeks to recover any additional amounts in a subsequent general rate filing, PGE must demonstrate the prudence of such additional costs.

Q. Did Staff examine the Clackamas Surface Collector project?

A. Yes. Staff reviewed the Company's filing and data requests about this project.

Q. What were Staff's findings?

A. Staff finds that PGE's pursuit of this project was prudent because it is a requirement of the hydro relicensing settlement agreement which was included in PGE's FERC license for the Clackamas Hydro Project. PGE expects the collector to be operational in the fall of 2015.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1701

Exhibits in Support of Staff Testimony

August 14, 2015

PORTLAND GENERAL ELECTRIC CO / OR/

FORM 8-K
(Current report filing)

Filed 06/03/13 for the Period Ending 05/30/13

Address	121 SW SALMON ST 1WTC0501 PORTLAND, OR 97204
Telephone	5034647779
CIK	0000784977
Symbol	POR
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): May 30, 2013

PORTLAND GENERAL ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Oregon	001-5532-99	93-0256820
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

121 SW Salmon Street, Portland, Oregon 97204
(Address of principal executive offices, including zip code)

Registrant’s telephone number, including area code: (503) 464-8000

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.06 Material Impairments.

Cascade Crossing Project Update

Since 2009, Portland General Electric Company (PGE, or the Company) has been in the process of developing new transmission capacity from Boardman, Oregon to Salem, Oregon, under a project known as the Cascade Crossing Transmission Project (Cascade Crossing). Cascade Crossing was included in PGE's 2009 integrated resource plan (IRP), which the Public Utility Commission of Oregon (OPUC) acknowledged in November 2010.

Cascade Crossing was originally proposed as a 215-mile, 500 kV transmission line to help meet future electricity demand. In January 2013, the Company entered into a non-binding memorandum of understanding (January MOU) with the Bonneville Power Administration (BPA) to pursue modifications to PGE's originally proposed project. Under the proposal described in the January MOU, the transmission line would terminate at a new substation called Pine Grove, near Maupin, Oregon (approximately midway between Boardman and Salem), eliminating the need for construction of approximately 101 miles of the originally proposed transmission line. The January MOU also provided that the parties would: (i) explore opportunities for PGE to invest in upgrades to BPA's system; (ii) analyze the possibility of asset exchanges; and (iii) work together to determine the feasibility of additional transmission projects under which PGE could obtain additional capacity between Boardman, Oregon and the Willamette Valley. Subject to the outcome of negotiations between the parties and continued evaluation of regional transmission needs and timing, the January MOU provided for PGE investments and conveyances in exchange for a total of up to 2,600 megawatts (MWs) of transmission capacity that could be staged to come on-line in phases as needed.

Based on subsequent analyses and an updated forecast of the demand for future transmission capacity in the region, PGE and BPA have continued to work toward refining the scope of Cascade Crossing. Conditions in the region have changed significantly since the OPUC acknowledged Cascade Crossing in PGE's 2009 IRP. The transmission needs for resource developers in the Northwest have changed, due in part to California's decision in 2011 to give preferential treatment to renewable energy projects developed in-state, as well as slower than expected regional load growth. At the same time, there has been construction of new transmission, which has increased the region's available capacity.

Over the past three months, PGE has had extensive discussions with BPA regarding new projections of available capacity. These discussions led to PGE's determination that original projections of transmission capacity limitations contemplated in the IRP process were not likely to fully materialize. In addition, the parties have explored alternatives that could provide PGE with needed transmission capacity at a lower cost to customers and with reduced environmental impact. As a result of these efforts, PGE and BPA executed a new non-binding memorandum of understanding on May 30, 2013 (May MOU) under which PGE has decided to suspend permitting and development of Cascade Crossing, and the parties will explore a new option under which BPA could provide PGE with ownership of approximately 1,500 MW in transmission capacity phased in over the next few years, in exchange for certain PGE assets, investments and/or PGE transfer capabilities to BPA. In a subsequent phase, PGE could also obtain ownership of up to an additional 1,100 MW of transmission capacity through system upgrades and/or expansion that is not expected to be needed before 2020. Timing and costs of these transmission capacity resources may be clarified through future discussions with BPA. BPA and the Company are working cooperatively to pursue single utility transmission planning that is consistent with FERC's objectives regarding regional planning and the parties' collective desire to minimize social and environmental impacts while facilitating PGE's need for additional transmission capacity to serve its customers in an efficient manner. The parties will continue discussions and negotiations to reach a definitive agreement concerning the options described in the May MOU. However, there is no assurance that the May MOU will result in a binding agreement.

As a result of the decision to suspend permitting and development of Cascade Crossing, the Company determined on May 30, 2013 that it will record a pre-tax loss of approximately $52 million ($31 million after-tax) for the costs currently recorded as construction work in progress related to the development of Cascade Crossing. This will be recorded as production and distribution expense during the second quarter of 2013. The Company also made a filing with the OPUC on June 3, 2013 seeking deferral of these costs for future recovery in customer prices. Management is unable to predict at this time what amount of these costs, if any, will ultimately be recoverable through customer prices. At such time that any portion of these costs become probable of recovery, the Company will record the related amount as a regulatory asset, with a corresponding reduction to expense.

Item 7.01 Regulation FD Disclosure.

Earnings Guidance

For 2013, PGE previously disclosed its forecasted full year earnings guidance of $1.85 to $2.00 per diluted share. As a result of the items outlined in this report on Form 8-K, the Company has revised its 2013 earnings guidance range to $1.35 to $1.50 per diluted share.

Item 8.01 Other Events.

Integrated Resource Plan Update

On June 3, 2013, PGE completed the competitive bidding process and subsequent negotiations to acquire two new power plants that were part of the Company's implementation of its current IRP, which the OPUC acknowledged in November 2010. The power plants emerged as the best performing bids with the best balance of cost and risk in requests for proposals (RFPs) PGE issued in 2012 seeking resources to help meet the Company's energy needs and Oregon's renewable portfolio standards.

Accion Group, Inc., an independent evaluator (IE) selected by the OPUC, oversaw the RFPs and review of the bids to assure an objective and impartial process. The IE issued reports earlier this year that confirmed the RFPs were conducted in a fair and unbiased manner and the final short lists accurately identified the bids with the most value for PGE customers.

New Energy Resource

The Company has entered into an agreement for the construction of a new 440 MW natural gas-fired power plant in eastern Oregon to meet the base load energy requirements outlined in the RFP for energy and capacity resources. The new facility, known as the Carty Generating Station, will be built by Abeinsa Abener Teyma, an affiliate of international developer and contractor Abengoa S.A. that specializes in turn-key projects for thermal generation, and will be owned and operated by PGE. The facility is scheduled to be in service in 2016 and the estimated total cost of the project is $440 million to $455 million, excluding allowance for funds used during construction.

New Renewable Resource

The Company also announced that it has entered into agreements for the development of a new wind farm known as the Lower Snake River Phase 2 project, with a nameplate capacity of 267 MWs to be constructed in eastern Washington to meet the requirements outlined in the Company's RFP for renewable resources. Under these agreements, PGE would acquire development rights to the project from Puget Sound Energy, Inc. and RES America Construction Inc. would construct the project for PGE, installing 116 turbines, each with a generating capacity of 2.3 MWs, manufactured by Siemens Energy, Inc. The project will be owned and operated by PGE. The transaction is expected to close in August 2013, subject to customary conditions.

The anticipated cost of the project is between $520 million and $535 million, excluding allowance for funds used during construction. Project construction and related milestones have been structured to enable the project to qualify for federal production tax credits. Subject to closing, the project is expected to be completed in 2015. The project will help PGE meet its obligation under the Oregon Renewable Portfolio Standard, which requires the Company to provide 15% of its retail energy deliveries from renewable sources beginning in 2015.

Petition for Declaratory Ruling

On May 31, 2013, Troutdale Energy Center, LLC (TEC) submitted a Petition for Declaratory Ruling to the OPUC requesting that the OPUC issue a number of declarations concerning PGE's ability to recover costs related to Cascade Crossing, the Port Westward Unit 2 Plant and the Carty Generating Station. TEC alleges that (i) PGE did not update the OPUC on the status and viability of Cascade Crossing and that this alleged failure directly impacted the scoring for the Company's energy and capacity RFP, (ii) PGE gave itself an undue or unreasonable preference or advantage through the scoring criteria it used and (iii) PGE did not evaluate, in a fair and reasonable manner, bids for projects located within PGE's control area and service territory that provided an alternative to developing transmission projects, such as Cascade Crossing. PGE believes the Petition is without merit and intends to ask the OPUC to dismiss the request.

Customer Billing Matter

In May 2013, PGE discovered that it had over-billed an industrial customer as a result of a meter configuration error that occurred over several years. An analysis of the data determined that the Company's revenues were overstated during that period in the aggregate by approximately $9 million. Management believes the customer billing error is not material to any past annual reporting period. The error overstated revenues by $2.5 million in 2012, $2.5 million in 2011 and $1.8 million in 2010, and will be corrected by the Company as an approximate $9 million pre-tax (approximately $5 million after-tax) out of period adjustment in the quarter ending June 30, 2013.

New Accounting Pronouncement

On January 1, 2013, PGE adopted Accounting Standards Update (ASU) No. 2011-11, *Disclosures about Offsetting Assets and Liabilities* and ASU No. 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* , on a retrospective basis. The new guidance requires enhanced disclosures regarding an entity's ability to offset certain instruments on the balance sheet and how offsetting impacts the balance sheets. The adoption of this guidance resulted in expanded disclosures relating to its derivative instruments but did not otherwise impact the Company's financial statements. As management does not consider the disclosures to be material to the annual consolidated financial statements as of December 31, 2012 and 2011, those annual financial statements have not been updated to reflect these disclosures.

Information Regarding Forward-Looking Statements

This current report includes forward-looking statements. Portland General Electric Company based these forward-looking statements on its current expectations about future events in light of its knowledge of facts as of the date of this current report and its assumptions about future circumstances. Investors are cautioned that any such forward-looking statements are subject to risks and uncertainties and that actual results may differ materially from those projected in the forward-looking statements, which include statements concerning the expected completion of capital projects, statements concerning the expected cost and completion dates of such projects, and statements concerning the possible outcome of discussions and negotiations with BPA concerning the May MOU. The Company assumes no obligation to update any such forward-looking statement. Prospective investors should also review the risks and uncertainties included in the Company's most recent Annual Report on Form 10-K and the Company's reports on Forms 10-Q and 8-K filed with the United States Securities and Exchange Commission, including Management's Discussion and Analysis of Financial Condition and Results of Operations and the risks described therein from time to time.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PORTLAND GENERAL ELECTRIC COMPANY
(Registrant)

Date: June 3, 2013

By: /s/ James F. Lobdell
James F. Lobdell
Senior Vice President of Finance,
Chief Financial Officer and Treasurer

CASE: UE 294
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1702

Exhibits in Support of
Staff Testimony

August 14, 2015

STAFF EXHIBIT 1702

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 15-036 IN UE 294

CASE: UE 294
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1703

Exhibits in Support of
Staff Testimony

August 14, 2015

May 7, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 433
Dated April 23, 2015

Request:

Regarding Exhibit UE 294/PGE/300, Pope – Lobdell/9, Lines 19-20, and Pope – Lobdell/10, Lines 1-5, where the Company represented:

> **"*Abeinsa will construct a 500 kV switchyard, known as the Grassland Switchyard (Grassland), to integrate Carty into the existing Boardman-Slatt generation lead. Abeinsa will remove a portion of the existing facilities transferring energy between Boardman and Slatt (identified by the dashed line) [as shown in Exhibit UE 294/PGE/300, Pope – Lobdell/10]. Carty, along with Boardman, will be connected to Grassland, and a single generation lead will continue to run to Slatt. Grassland will allow one plant to continue to deliver energy even if the other plant trips offline.*"**

Please:

a. Provide comprehensive explanation whether or not the Grassland Switchyard would have been built *absent* the Company's building of the Carty Generation Station. Please provide copies of the documentation justifying the Company's response (e.g., generation planning documents, transmission planning documents, etc.) and indicate the page numbers where relevant parts upon which the Company relied in answering this question are located.

If the information requested in the above question was derived or obtained from other sources, please identify each such specific source and provide a copy of each such specific source document in portable document format (PDF) file(s), MS Word file(s), Excel workbook (with cell references and formulae intact) file(s), or any other common document format indicating the specific page, section, etc. of the relevant source document.

Response:

No, PGE would not have built Grassland absent the construction of the Carty Generating Station (Carty). However, as described in PGE's response to OPUC Data Request No. 378, Grassland performs the function of "generation integration" for both Carty and the Boardman Generating Plant (Boardman) and is scheduled to begin serving Boardman by June 2015. As part of interconnecting through Grassland, Boardman will also employ a more modern protection and communication system. PGE replaced Boardman's old protective relays, which increases system protection. PGE also added a new fiber communication system at Boardman, which improved overall system reliability.

CASE: UE 294
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1800

STAFF TESTIMONY IN SUPPORT OF THE PARTIAL STIPULATION

August 14, 2015

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

A. My name is Phil Boyle. I am the Consumer Services Manager with the Public Utility Commission of Oregon. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1801.

Q. What is the purpose of your testimony?

A. To discuss the Fee Free Bankcard proposal in order to provide support for the partial stipulation in this docket.

Q. Did you prepare any exhibits other than your qualification exhibit for this docket?

A. Yes. I include Exhibit Staff/1802, which contains PGE's response to Staff DR 468 requesting an update to their transaction cost model. This exhibit does not include the confidential attachment that was included in the Company's response to Staff DR 468.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Residential Program

Q. Did you review PGE's proposal to continue to offer the fee free bankcard payment option to residential customers in 2016?

A. Yes. In its initial filing, the Company proposed continuation of the Fee Free Bankcard payment option which was originally approved in Docket UE 262, Order No. 14-422, and launched on September 30, 2014. In this docket, the Company forecasted $2.3 million to cover the fee-free bankcard program costs in the 2016 test year for both residential customers and the proposed commercial expansion. *See* UE 294, Exhibit PGE/900, Stathis-Dillin/15. I reviewed the company's cost model and assumptions. PGE projected a year-end 2015 customer adoption rate of 11.1 percent, and a year-end 2016 adoption rate of 17 percent. Using these starting and ending points, PGE projected total credit/debit card payment transactions during 2016. PGE assumed that 43 percent of card payments will be made with credit cards, and 57 percent will be made with debit cards for its original filing. PGE's confidential model for transaction costs provides an estimate of the cost per transaction for credit card payments versus debit card payments, with credit card payment transactions being more costly to process. The model uses an average payment amount, which impacts the fee structure. Part of the cost of processing transactions under the fee-free bankcard program is related to the size of the payment.

Staff issued twelve data requests to the Company on this topic prior to the partial stipulation, and one data request was issued after the Parties reached agreement regarding the residential program. Staff's data requests ask about various aspects of the Company proposal in order to gain a full understanding of the assumptions the Company used to arrive at their proposed starting and ending adoption rates, and calculated number of transactions. Staff's data requests also explored allocation of costs, the impact on uncollectables, demographic information about who is using this payment option, research about other utility card payment programs, and actual adoption rates achieved since the program launch in September 2014.

Q. What were Staff's findings regarding the fee-free bankcard program for residential customers?

A. The Company's responses to Staff data requests included a 2013 survey that detailed two other utilities' experiences with fee-free bankcard adoption rates over time. To Staff, this data suggested that PGE's proposed starting adoption rate of 11.1 percent, ending adoption rate of 17 percent and monthly adoption growth rate of .49 percent were too high, resulting in an unrealistically high number of payment transactions, and higher than necessary program costs. I modified PGE's cost model using six months of actual adoption rate data since the program launched in September 2014, and year-end penetration rates for two other utilities offering a fee free bankcard payment option. From this information, I was able to calculate what Staff views as more realistic 2015 and 2016 year-end adoption rates and monthly adoption growth projections. My calculations resulted in projected year-end 2015 and 2016 adoption rates of 9.1

percent and 13.1 percent respectively, and a monthly adoption growth rate of .33 percent, resulting in a lower number of projected bankcard transactions.

Q. Did you also review the demographics of the users of the fee free bankcard program?

A. Yes. In its initial testimony, the Company provided Exhibit PGE/903 which provides demographic information about who the primary users of a Fee Free Bankcard program are. They are more likely to be renters, have only a high school education, have a lower credit score, and tend to be lower income. Over 50 percent of bankcard program users have received a late notice and 38 percent have received a disconnect notice in the last 12 months. Being able to pay their electric bill without being assessed a transaction fee is a valuable benefit to customers with these demographic characteristics.

Q. Did Staff conduct any further analysis?

A. Yes. Following the first settlement conference held on May 21st, Staff considered that the mix of users of the fee-free bankcard program are much more likely -- as noted above -- to use credit cards rather than debit cards. According to PGE's response to an additional data request, review of the data now available has shown that closer to 80 percent of the card transactions are done using a credit card rather than the original projection of 43 percent, and debit card transactions are closer to 20 percent of all transactions rather than the 57 percent originally projected.

Also, the Company has updated the original model to assume the average payment amount of program participants, for which data which is now available, rather than the average Schedule 7 residential customer's payment. Compared to $98 for the average Schedule 7 payment, the average actual payment has been closer to $150. The Company has projected the average 2016 Fee Free Bankcard payment to be $168.94. This is significant as the higher the payment, the higher the transaction costs.

The transaction cost for the program is determined by two primary factors: the mix of credit and debit card use and average amount of the payment. The combined effect of the higher percentage of credit card transactions and the higher payment amount by program users has resulted in an increased average transaction cost.

Q. How was the issue of the fee-free bankcard program addressed in this docket?

A. The issue was resolved by the stipulating parties. Staff's proposed adjustments to the fee free bankcard program, along with adjustments to D&O insurance, A&G, wages and salaries, pensions, and escalation, and issues related to capital additions related to the Northfork Surface Collector and Grassland Switchyard, Carty and coal inventory, were settled as a group for an $8 million reduction in the Company's revenue requirement and a $9 million reduction in rate base. As part of the stipulation, PGE agrees with Staff's residential bankcard program adoption rate of 9.1 percent for 2015 and 13.06 percent for 2016. The stipulating parties agree to additional terms regarding the commercial fee free bankcard program, which are discussed below.

Staff supports the settlement with PGE as reasonable and finds that it reflects the higher credit card use as well as a higher average residential bill being paid,

Issue 2, Commercial Program

Q. Did you review PGE's proposal to extend the fee-free bankcard payment option to commercial customers in 2016?

A. Yes. Once again, as in UE 262 and UE 283, PGE proposes at a later time to expand the fee-free bankcard payment option to commercial customers. Company projections indicated an adoption rate to go from zero at the start of 2016 to 10 percent by the end of the year, and program costs of $172,000. See UE 294, Exhibit PGE/900, Stathis-Dillin/15.

Staff issued six data requests about the proposed commercial program to gain an understanding of how the company arrived at their projected year-end adoption rate, monthly adoption growth rate, and number of transactions. Some of the data requests also requested information about any research the company did with commercial customers about their desire for such a program, and other utilities' experience.

Staff is not supportive of expanding the fee-free bankcard program to commercial customers.

Q. Did the Parties reach agreement on a commercial program?

A. The Parties have agreed that PGE will not extend the payment option to commercial customers in 2016. The Company also agreed to provide Staff with at least 45 days' notice before launching a program to offer a fee-free bankcard payment option to commercial customers after 2016.

Q. Please summarize Staff's position regarding the fee-free bankcard payment program?

A. Staff supports the stipulation that PGE continue to offer the fee-free bankcard payment option to residential customers in 2016, to exclude extending this payment option to commercial customers in 2016, and that the Commission will receive at least 45 days' notice of Company intention to extend this payment option to commercial customers at any time after 2016. I also support including the $1.96 million revenue requirement expense associated with providing the fee-free bankcard program to residential customers as part of the group of Staff adjustments that were settled for an $8 million reduction in test year expenses and $9 million reduction in rate base.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 294
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1801

Witness Qualification Statement

August 14, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME:	Phil Boyle
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Program Manager Consumer Services Section
ADDRESS:	201 High Street SE., Suite 100 Salem, OR 97301
EDUCATION:	Bachelor of Science (Education), Portland State University, 1980
EXPERIENCE:	1980 to 2003 – PacifiCorp I worked at PacifiCorp (Pacific Power) in a variety of customer facing positions over the years, starting as an Energy Consultant, progressing through Sales and Commercial Account Manager position's, to local District Manager and Customer Service Manager. In my 23 years at PacifiCorp I learned about all aspects of customer service and distribution operations. 2004 to 2005 – Oregon Department of Revenue Worked in collections unit collecting delinquent taxes. 2005 to Present – Oregon Public Utility Commission I am currently Program Manager for the Consumer Services Section, beginning my work with the PUC as a Consumer Specialist, advancing to a Senior Compliance Specialist and finally to Program Manager. In these roles I have become very experienced working with utilities to help them comply with Division 21 Administrative Rules.

CASE: UE 294
WITNESS: PHIL BOYLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1802

Exhibits in Support of
Staff Testimony

August 14, 2015

June 15, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 468
Dated June 1, 2015

Request:

Please provide the updated transaction cost model for the fee free bankcard program reflecting current credit card and debit card usage rates, and reflecting an updated average billing amount.

Response:

Attachment 468-A provides the updated fee-free bankcard (FFBC) program transaction cost model and fee structure reflecting current credit and debit card use as described below.

Attachment 468-A is Confidential and Subject to Protective Order No. 15-036.

Debit versus credit card use and proportion of use:
In its original filing, PGE assumed bank card use at 57% debit card use and 43% credit card use. When actual use history became available, PGE realized that we understated the cost in our original filing. Actual residential program participant card use is significantly different and is currently at 16.59% debit card use and 83.41% credit card use (see tab 'Fee Structure & Assumptions, Cell F70 and F71). Credit cards have the highest transactional cost amount the two.

Average Payment Amount:
In its FFBC model, PGE uses the average *payment* (rather than billing) amount because the transaction costs are based on the size of the payments and the number of transactions. These factors impact the fees paid to the vendor. The average *bill* amount is calculated using consumption while FFBC fees are calculated using payments received. The average historical bill amount for all Schedule 7 (residential) customers is

$93.50 (see Tab 'Fee Structure & Assumptions', Cell N51), while the average program participant's bill is $154.12 (see Tab 'Fee Structure & Assumptions', Cell P51).

In its original FFBC model, PGE used the average Schedule 7 residential customer payment of $98 which is understated compared to the actual program participants average payment amount of $154.12 (see above).

For the 2016 test year, however, PGE calculates the average forecasted 2016 program participants payment at $168.94 (see tab 'Fee Structure & Assumptions', Cell U51) based on the variance between the payments and bills of program participants as explained in rows 43-46 under the 'Fee Structure & Assumption' tab. This payment level directly impacts the fee structure and the fees paid to the vendor.

These updated costs result in a total program cost of $1.96 million, and a total cost per transaction of $1.94 (see tab 2016 Residential Adoption Rate', Cell H59, and Cell H61, respectively.

UE 294

Attachment 468-A

Provided in Electronic Format only

Updated Bank Card Model

Confidential and Subject to Protective Order No. 15-036