Oregon

Theodore R. Kulongoski, Governor

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August 9th, 2006

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **Docket Nos. UE 180/ UE 181/ UE 184** - In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180), 2007 Resource Valuation Mechanism (UE 181) and Request for a General Revision relating to the Port Westward Plant (UE 184).

Enclosed for electronic filing in the above-captioned dockets is the Public Utility Commission Staff's Opening Testimony.

/s/ Kay Barnes
Kay Barnes
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
(503) 378-5763
Email: kay.barnes@state.or.us

c: UE 180/UE 181/UE 184 Service List - parties

PUBLIC UTILITY COMMISSION OF OREGON

UE 180/UE 181/UE 184

STAFF DIRECT TESTIMONY OF

Carla Owings
Judy Johnson
Lisa Schwartz
J.R. Gonzalez
Maury Galbraith
Steve W Chriss

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision (UE 180), 2007 Resource Valuation Mechanism (UE 181), And Request for a General Revision relating to the Port Westward Plant (UE 184).

August 9, 2006

CASE: UE 180/UE 181/UE 184
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Direct Testimony

August 9, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Carla Owings. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I am a Senior Revenue Requirements analyst employed by the Public Utility Commission. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. As the Revenue Requirement Analyst for this proceeding, I will testify to the adjustments proposed by Commission Staff (Staff) to Portland General Electric Company's (PGE's) application as agreed upon in a stipulated agreement filed in this docket, as well as introduce adjustments sponsored by other Staff members that are not included in the stipulation. I will also explain the overall impact to PGE's requested revenue requirement.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/402, consisting of 16 pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into four parts. Part I of my testimony summarizes the revenue requirement impact of the adjustments agreed upon by Staff, PGE, the Citizens' Utility Board (CUB), Fred Meyer, the City of Portland and the Industrial Customers of Northwest Utilities (ICNU). Part II explains the revenue requirement model and all exhibits submitted in support of the model adjustments. Part III of my testimony introduces adjustments sponsored by other Staff witnesses and a brief explanation summarizing the revenue requirement impacts of each witness' proposed adjustment. Part IV of my testimony addresses issues SOI-2 and SOI-3, non-revenue requirement impact issues I raise for final consideration in this docket.

PART I:
RATE CASE SUMMARY

Q. PLEASE SUMMARIZE THE COMPANY'S RATE REQUEST AND STAFF'S FINDINGS REGARDING REVENUE REQUIREMENT.

A. On March 15, 2006, PGE filed an application for a general rate increase pursuant to ORS 757.205 and ORS 757.220 effective January 1, 2007, docketed as UE 180. The application proposes to increase PGE's revenues by $25 million on an annual basis. On March 28, 2006, PGE filed an application docketed as UE 181, requesting to update its Resource Valuation Mechanism (RVM) effective January 1, 2007. On April 5, 2006, the Commission approved the Company's request to consolidate docket UE 180 and UE 181. On a consolidated basis, PGE's request to update its RVM increased its revenue requirement request by an additional $73 million, for a total revenue requirement increase of $97.9 million. This represents a 6.26 percent overall increase to current rates.

On April 24, 2006, PGE filed an application docketed as UE 184 requesting a waiver pursuant to OAR 860-022-0017 and a motion to consolidate this application with docket UE 180 in consideration of an additional rate increase to become effective March 1, 2007, for costs associated with the Port Westward generating facility. This request represents an additional revenue requirement increase of approximately $45 million, or an additional 2.87 percent increase over its request in the general rate proceeding, docket UE 180. The Company's overall request, including updates to its power costs and Port Westward, was approximately $143 million or 9.3 percent increase from current rates. The Company filed testimony, exhibits and work papers supporting its rate increase request.

Staff has evaluated the Company's proposal and examined the work papers and supplementary data supplied in response to data requests. Staff's findings resulted in identification of approximately fifteen adjustments that impact the revenue requirement request in the Company's application for the general rate proceeding including its updated forecast for power costs along with eight issues that do not affect the revenue requirement. Additionally, Staff identified two issues impacting the Company's application for a rate increase after the implementation of Port Westward. Of the first fifteen issues, Staff and several of the intervening parties were able to come to an agreement on eleven. These issues are supported in the stipulated agreement and supporting joint testimony to be filed in this proceeding. The two adjustments impacting the rate application after the implementation of Port Westward are discussed in Part II of my testimony. Based on the stipulated agreement and Staff's analysis of the remaining issues, we propose that the appropriate increase in revenues, not including the Port Westward facility, should be

$19.7 million on an annual basis for base rates including updated power costs to become effective January 1, 2007, or an overall rate increase of 2.6 percent. For March 1, 2007, the expected commercial operation date for Port Westward, Staff proposes that the appropriate increase in revenues should be an additional $38.4 million on an annual basis, or an additional increase of 3.6 percent. On a consolidated basis, this represents an overall increase of 6.3 percent to current rates.

PART II:
REVENUE REQUIREMENT MODELING

Q. PLEASE EXPLAIN EXHIBIT 402.

A. Staff Exhibit/402 is a series of interlinked spreadsheets that contain ten separate elements that, together, summarize Staff's position on the revenue requirement adjustments for UE 180, UE 181 and UE 184. The models are formatted into two phases. The first phase is the portion of the case containing the Company's general rate increase request submitted in docket UE 180 and includes its forecasted updates for power costs submitted in docket UE 181. The second phase is the Company's request to increase operations and maintenance expenses and add costs to rate base to reflect the implementation of the Port Westward generating facility. The spreadsheets are formatted as follows:

1. Page 1 is a summary showing the changes to revenues, expenses and rate base and ends with the percentage change from current rates. Column (1) represents the Company's results of operations for the test period. Column

(2) shows the results of operations for the Company if the stipulated agreement were adopted by the Commission and all other adjustments proposed by Staff for the first phase of this docket were also adopted by the Commission. Column (3) represents the Company's application as it pertains to changes for Port Westward and Column (4) represents Staff's proposed adjustments to the Company's application for Port Westward changes.

2. Pages 2 through 4 are narrative summary sheets that begin with the Company's original revenue requirement request for the general proceeding and include the update to power costs submitted in docket UE 181. Staff provides a short description of each of the proposed adjustments. The first column indicates an item number assigned to the adjustment. The second column indicates the Staff Witness sponsoring the adjustment and the far right column indicates the revenue requirement impact of the proposed adjustment. Staff's proposed overall revenue requirement for the portion of the proceeding, not including the Port Westward costs, can be found on the bottom of page 3, in the far right column. The top of page 4 begins a list of additional issues raised by Staff based on its review of the Company's filing. While these issues have no revenue requirement impact, Staff proposes that the Commission consider these issues when making its final decisions in this docket. I will address these issues more specifically in Parts III and IV of my testimony.

3. Pages 5 and 6 are the spreadsheets containing the modeling for revenue requirement for each phase of the proceeding. Page 5 contains the

information pertinent to the first phase (the Company's rate request including updated power costs and the general rate increase). Page 6 begins with the results from the first phase and then moves to the second phase, the Company's proposed additional revenue requirement for the Port Westward costs. More specifically, beginning on Page 5, Column (1) contains the Company's original results of operations for the CY 2007 test period. Column (2) contains the results of the stipulated agreement and Staff's proposed additional adjustments to revenues, expenses and rate base for phase one of the Company's case. The next column, column (3), is the adjusted results of operations (column (1) plus column (2)). Column (4) shows the required change in revenues necessary for a reasonable rate of return, for the first phase and is shown as the first number at the top of column (4). Column (5) shows the cumulative results of operations with a reasonable rate of return. Continuing on to page 6, Column (6) shows the Company's proposed changes to expenses and rate base on March 1, 2007, associated with the implementation of Port Westward. Column (7) shows the adjusted results from the original proposed increase (column (5) plus column (6)). Column (8) shows Staff's proposed adjustments to the changes in expenses and rate base. The next column, Column (9), again shows the cumulative effect of Staff's proposed adjustments. Column (10) shows the required change in revenues necessary for a reasonable rate of return, including Port Westward. The proposed revenue requirement is the first number appearing at the top of column (10) for the second phase of this proceeding.

Column (11) shows the final outcome of all changes to revenues, expenses and rate base under Staff's proposed adjustments.

4. Pages 7 and 8 contain the income tax calculations for the results of operations. Page 7 shows the tax calculations for phase one which includes updated power costs before the implementation of Port Westward. Page 8 shows the tax calculations after the implementation of Port Westward.

5. Pages 9 and 10 show the specific adjustments agreed to in the stipulation as well as the additional adjustments proposed by Staff for the revenue requirement request associated with the updated power costs before the implementation of Port Westward.

6. Pages 11 and 12 show the tax calculations associated with the adjustments shown on pages 9 and 10, prior to the implementation of Port Westward.

7. Page 13 shows a narrative summary in the same format as shown on pages 2 and 3 of this exhibit; however, this narrative summary is pertinent to Staff's proposed adjustments after the implementation of Port Westward.

8. Page 14 shows Staff's proposed adjustment to expenses and rate base after the implementation of Port Westward.

9. Page 15 shows the tax calculation associated with the adjustment proposed on page 14.

10. Page 16 shows the revenue sensitive costs associated with the revenue requirement calculation and a summary of the cost of capital proposed by Staff.

PART III:
SUMMARY OF ADJUSTMENTS

Q. COULD YOU PLEASE BRIEFLY EXPLAIN WHICH ADJUSTMENTS ARE REPRESENTED IN JOINT TESTIMONY AND WHICH ADJUSTMENTS REMAIN AS AN ISSUE TO BE DECIDED IN THIS DOCKET?

A. Yes. Staff has met with the Company and intervening parties on four separate occasions, including two phone conferences. The parties to the stipulation agreed to settle on the following issues:

(S-1) Taxes other than State and Federal;
(S-3) Administrative and General Expenses;
(S-5) Incentives;
(S-6) Wages & Salaries;
(S-8) Other Revenues;
(S-9) Capital Expenditures;
(S-11) System Losses;
(S-12) Memberships;
(S-13) Tenant Improvements;
(S-14) Weatherization; and
(S-15) Customer Service and Information Expense.

The cumulative impact of this agreement is a reduction to Operations and Maintenance expenses of $18.4 million, a reduction to rate base of $8 million and an increase to revenues of $40 million from the Company's original application.

Additionally, Staff, PGE, CUB, Fred Meyer, the City of Portland and ICNU have agreed upon the issues raised by Staff surrounding Direct Access referred to in this docket as SOI-4, SOI-5 and SOI-6. PGE is currently preparing a stipulation in the form of joint testimony in support of this agreement.

The remaining issues impacting revenue requirement are:

(S-ROR-A) and (S-ROR-B) Cost of Capital

(S-2) Federal Income Tax and State Income Tax;

(S-4) Net Variable Power Cost Adjustment and Forced Outage Rate;

(S-7) Coal Loss Adjustment; and

(S-10) Extrinsic Value.

Q. ARE THERE ANY REMAINING ISSUES THAT APPEAR IN YOUR REVENUE REQUIREMENT MODELS THAT YOU HAVE NOT DISCUSSED HERE?

A. Yes. Issue S-PW-2. This adjustment can be found at Exhibit Staff/**402/Owings/13**. This adjustment reflects a stipulated agreement between Staff and PGE (the Parties) pursuant to docket no. UM 1233, PGE's Depreciation Study. In its 2005 Depreciation Study, PGE reflected the estimated depreciable life for Port Westward as 28.5 years. The stipulated agreement associated with that docket revises that life estimate to 35 years. This results in an annual decrease of depreciation expense of $1.988 million and an offsetting ratebase adjustment of $994,225. While the life estimate is being sponsored in joint testimony for docket UM 1233, the revenue requirement impact affects the application for UE 180/UE 184. Therefore, Staff is sponsoring this impact as a portion of this testimony.

Q. COULD YOU PLEASE PROVIDE MORE INFORMATION ABOUT EACH REMAINING ADJUSTMENT?

A. Yes. Issue S-ROR-A and S-ROR-B are the impacts to revenue requirement due to Staff's proposed change to the cost of capital. Staff witness Bryan Conway will address Staff's findings as they relate to the cost of debt in Exhibit Staff/900. Staff's recommendations for the cost of equity will be supported in Exhibit Staff/1000 by Staff witness Thomas Morgan. Issue S-2, FIT and SIT Deduction is a proposal by Staff to adjust the interest calculation for rate base associated with Staff's proposed cost of capital. This adjustment is sponsored by Staff witness Judy Johnson (*See* Exhibit Staff/500). Issue S-4, Net Variable Power Cost Adjustment/Forced Outage Rate Adjustment is Staff's proposed adjustments to the Monet modeling used to forecast power costs as well as Staff's proposed forced outage rates associated with the Boardman and Colstrip facilities. This issue is sponsored by Staff witness Maury Galbraith in direct testimony filed on July 18, 2006 (*See* Exhibit Staff/100). Issue S-7, Coal Loss Adjustment is Staff's proposal to disallow costs associated with the loss of coal during transportation. This issue, sponsored by Staff witness Ed Durrenberger, is supported in direct testimony filed on July 18, 2006 (*See* Exhibit Staff/300). Issue S-10, Extrinsic Value is Staff's proposal to adjust for value associated with flexible power resources not dispatched through Monet Modeling. Staff witness Bill Wordley supports this adjustment in his testimony filed on July 18, 2006 (See Exhibit Staff/200).

Q. PLEASE DESCRIBE THE REMAINDER OF STAFF'S DIRECT TESTIMONY FILED IN THIS DOCKET.

A. Staff Witness Lisa Schwartz will file testimony Exhibit Staff/600 to support her recommendations associated with the Company's proposals as they relate to partial requirements (SOI-1). Additionally, Ms. Schwartz and Staff witness JR Gonzalez will address Staff's recommendations as they relate to Advanced Metering Infrastructure (*See* Exhibit Staff/600 and Exhibit Staff/700).

In Part IV of my testimony, I will address the amortization of a $20 million credit associated with the Trojan Decommissioning costs (SOI-2) and the amortization of a credit attributable to 2002 Schedule 127, Part C (SOI-3). Lastly, Staff witness Maury Galbraith will support Staff's recommendations as they relate to the Power Cost Adjustment (PCA) mechanism proposed by PGE and Staff's position regarding the prudence review for the Port Westward costs (*See* Exhibit Staff/800).

PART IV:

NON-REVENUE REQUIREMENT ISSUES

Q. COULD YOU PLEASE DESCRIBE IN DETAIL THE ISSUES SURROUNDING THE AMORTIZATION OF THE $20 MILLION TROJAN CREDIT?

A. Yes. The Company describes, in its direct testimony, an accrued savings from the decommissioning costs approved in UE 115 of $20 million (*See* PGE/1000/Quennoz-Nichols/1). The Company states that it intends to return the funds to customers in the near future. However, as of the date of the filing the Company had no recommendation for any particular ratemaking treatment for the accrued savings. The Company has proposed in this filing, to reduce the annual customer contribution for Trojan decommissioning from $14 million down to $4.6 million. Although Staff recognizes the significant decrease in the customer contribution in the Company's proposal, Staff proposes that the accrued savings be used to further reduce ratepayers' annual contribution. Further reducing the annual contribution recognizes that these funds are attributable to the ratepayers who have contributed to the decomissioning and prevents future suggestions by the Company to attribute these funds to other interests or future needs. Immediate ratemaking treatment of the $20 million lessens the amount of interest due the ratepayers and provides an immediate tangible benefit for customers.

Q. WHAT ISSUES SURROUND STAFF'S PROPOSAL TO AMORTIZE THE CREDIT ASSOCIATED WITH SCHEDULE 127, PART C?

A. In its 2002 Resource Valuation Mechanism, PGE over-amortized some power costs. In other words, the Company over-collected on costs which resulted in a credit of approximately $1.5 million as of December 31, 2006 on Part C of Schedule 127. Since Schedule 127 is no longer a current tariff schedule, Staff proposes that the Company use this credit to off-set costs on Schedule 105, regulatory adjustments.

Q. DOES PGE AGREE WITH STAFF'S PROPOSALS AS THEY RELATE TO THESE TWO ISSUES?

A. The Company remained neutral on Staff's proposals for these two issues and did not directly comment on them during its discussions with Staff. In response to Staff's Data request number 201, PGE states that it does not propose a specific ratemaking treatment for the $1.5 million credit. Additionally, in response to Staff's Data request number 199, related to the $20 million credit resulting from the Trojan decommissioning costs, the Company simply states that the funds are "available" for ratemaking treatment. Staff urges the Commission to take a pro-active stance and require the Company to refund these credits as proposed by Staff.

Q. DO YOU HAVE ANYTHING FURTHER ON THESE ISSUES OR ANY OTHER ISSUES?

A. No.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 180/UE 181/UE 184
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

August 9, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	Carla M. Owings
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst/Revenue Requirement/Rates and Regulation
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	Professional Accounting Degree Trend College of Business 1983
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April of 2001. I am the Senior Utility Analyst for revenue requirement for the Rates and Regulation Division of the Utility Program. Current responsibilities include leading research and providing technical support on a wide range of policy issues for electric, telecommunications, and gas utilities. From September 1994 to April 2001, I worked for the Oregon Department of Revenue as a Senior Industrial/Utility Appraiser. I was responsible for the valuation of large industrial properties as well as utility companies throughout the State of Oregon.
OTHER EXPERIENCE:	I received my certification from the National Association of State Boards of Accountancy in the Principles of Public Utilities Operations and Management in March of 1997. I have attended the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2002 and the College of Business Administration and Economics at New Mexico State University's Center for Public Utilities in May of 2004. In 2005, I attended the National Association of Regulatory Utility Commissioners Advanced Course at Michigan State University. I worked for seven years for the Oregon State Department of Revenue as a Senior Utility and Industrial Appraiser.

CASE: UE 180/UE 181/UE 184
WITNESS: Carla Owings

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support of Direct Testimony

August 9, 2006

Portland General Electric
UE 180
December 31, 2007
(000)

	DESCRIPTION	PER APPLICATION Before PW (1)	STAFF PROPOSED Before PW (2)	PER APPLICATION After PW (3)	STAFF PROPOSED After PW (4)
1	**Rate of Return Under Present Rates**				
2	**Total Combined Rate Base**	1,745,972	1,735,550	1,921,100	2,015,468
3					
4	**Revenues**				
5	Sales Revenues	1,546,707	1,566,373	1,644,624	1,604,840
6	Other Operating Revenues	17,728	19,416	17,728	19,416
7	**Total Operating Revenues**	1,564,435	1,585,789	1,662,352	1,624,256
8					
9	**Operating Expenses**				
10	Operation & Maintenance Expenses	1,177,769	1,134,504	1,175,298	1,131,717
11	Depreciation Expense	154,384	154,384	165,050	163,062
12	Amortization Expense	18,848	18,848	18,848	18,848
13	Taxes other than Income	47,497	45,230	47,497	45,230
14	Income Taxes	30,757	54,244	61,894	63,040
15	Miscellaneous Revenue and Expense(Franch. Fees)	36,193	36,653	38,484	37,553
18	**Total Operating Expenses**	1,465,448	1,443,863	1,507,071	1,459,456
19					
20	**Operating Income**				
21	**Operating Income**	98,987	141,951	155,281	164,800
24	**Rate of Return at present rates**	5.67%	8.18%	8.08%	8.18%
25					
26	**Development of Revenue Requirement**				
27	Rate of Return @ Company's Requested ROE	8.967%	8.179%	8.967%	8.179%
28					
29	Return at claimed rate of return	156,740		181,769	
30	Earnings Deficiency	57,753		26,488	
31					
32	Net to Gross Multiplier	1.696		1.696	
33	**Additional Revenue Requirement**	**97,917**	**19,666**	**44,911**	**38,467**
34	Revenue at Request Rate of Return	1,662,352	1,605,454	1,707,263	1,662,723
36					
37	**Percent change from current rates**	**6.26%**	**2.62%**	**9.13%**	**6.28%**

STAFF NARRATIVE SUMMARY SHEET
ADJUSTMENTS BEFORE PORT WESTWARD
December 31, 2007
($000)

Item	Staff	Issue	Revenue Requirement Effect
		Revenue Requirement on the Company's Filed Results	**$97,917**
		Proposed Staff Adjustments	
S-ROR A	BC	**Rate of Return** Staff proposed Cost of Capital Impact before Port Westward Addition	**($23,403)**
S-1	CO	**All Other Taxes** Adjustment reflecting stipulated agreement	**($2,339)**
S-2	JJ	**FIT and SIT Deduction** Staff proposes to adjust interest calculation to Staff's weighted cost of Capital	**($4,682)**
S-3	MD	**Administrative & General and Operations & Maintenance Adjustment** Adjustment reflecting stipulated agreement	**($6,761)**
S-4	MG	**Net Varible Power Cost Adjustment** Staff proposes to adjust Monet Model to reflect 4-yr forced outage rate of 8.62%	**($13,257)**
S-5	CO	**Incentive Adjustment** Adjustment reflecting stipulated agreement	**($4,654)**
S-6	CO	**Wages & Salary** Adjustment reflecting stipulated agreement	**($3,766)**
S-7	ED	**Coal Loss Adjustment** Staff proposes to remove Company's adjustment for coal loss.	**($366)**

STAFF NARRATIVE SUMMARY SHEET
ADJUSTMENTS BEFORE PORT WESTWARD
December 31, 2007
($000)

S-8	PR	**Adjustment to Other Revenues** Adjustment reflecting stipulated agreement	**($41)**
S-9	CO	**Capital Expenditures Adjustment** Adjustment reflecting stipulated agreement	**($815)**
S-10	BW	**Extrinsic Value** Staff proposes to adjust for flexible power resources not dispatched by Monet Modeling	**($14,436)**
S-11	BW	**System Losses** Adjustment reflecting stipulated agreement	**$0**
S-12	PR	**Membership Adjustment** Adjustment reflecting stipulated agreement	**($85)**
S-13	CO	**Tenant Improvements** Adjustment reflecting stipulated agreement	**$0**
S-14	MD	**Weatherization Adjustment** Adjustment reflecting stipulated agreement	**($71)**
S-15	DG	**Customer Service & Information Expense Adjustment** Adjustment reflecting stipulated agreement	**($1,626)**
S-16	BW	**Ancillary Services** Staff proposes to add revenues not included in the Test Period for Ancillary Services	**($1,691)**
S*		Revenue Sensitive Costs	**($258)**
		Total Staff-Proposed Adjustments (Base Rates):	(78,251)
		Staff-Calculated Revenue Requirements Change (Base Rates):	**$19,666**

STAFF NARRATIVE SUMMARY SHEET
ADJUSTMENTS BEFORE PORT WESTWARD
December 31, 2007
($000)

Other Issues

SOI-1	LS	Staff modifies PGE's proposed notification requirements for changing Baseline Demand due to changes in generating capacity or generation operations. Staff also proposes that certain terms used in special conditions in Schedules 75 and 575 be defined.	N/A
SOI-2	CO	Staff proposes to that the Company file a special rate schedule to amortize $20 million credit available in Trojan Decomissioning deferral account	N/A
SOI-3	CO	Staff proposes to that the Company file a special rate schedule to amortize $1.5 Million credit attributable to Part C Schedule 127.	N/A
SOI-4	MG	Staff opposes PGE's proposed long-term market-based pricing option for customers to opt-out of cost-of-service for three or five years.	N/A
SOI-5	MG	Staff opposes PGE's proposed 50-50 split load pricing option for large Direct Access customers.	N/A
SOI-6	MG	Staff opposes PGE's proposal to handle monthly balance-of-year Direct Access options through web postings and not through separate advice filings.	N/A
SOI-7	MD	Staff proposes to conduct an audit on software purchases to determine if costs have been properly categorized as capital or expense and to review the $250,000 capital threshold.	N/A
SOI-8	LS	AMI - Staff proposes that the Company make a supplemental tariff filing for accelerated write-off of exisiting metering capital as part of its advanced metering proposal.	N/A

Rate Case Staff and Contact Information

Initials		
BC	Bryan Conway	503-378-6200
CO	Carla Owings	503-378-6629
DG	Deborah Garcia	503-378-6688
ED	Ed Durrenberger	503-378-1536
JJ	Judy Johnson	503-378-6636
LS	Lisa Schwartz	503-378-8718
MD	Mike Dougherty	503-378-3623
MG	Maury Galbraith	503-378-6667
PR	Paul Rossow	503-378-6917

Portland General Electric
UE - 180
December 31, 2007
($000)

	SUMMARY SHEET	2007 Per application Includes Power Costs (1)	Staff Proposed Adjustments (2)	2007 Adjusted (3)	Revenue Req without Port Westward 1/1/2007 (4)	Results at Reasonable Return Inc. Pwr Costs (5)
1	**Operating Revenues**					
2	Retail Sales	$1,546,707	$0	$1,546,707	$19,666	$1,566,373
3	Wholesale Sales	0	0	0	0	0
4	Other Revenues	17,728	1,688	19,416	0	19,416
5	**Total Operating Revenues**	$1,564,435	$1,688	$1,566,123	$19,666	$1,585,789
6	**Operating Expenses**					
7	Net Variable Power Costs	$856,968	($26,838)	$830,130	$0	$830,130
8	Production	71,970	(354)	71,616	0	71,616
9	Other Power Supply (Trojan)	218	0	218	0	218
10	Transmission	10,279	(34)	10,245	0	10,245
11	Distribution	60,336	(1,623)	58,713	0	58,713
12	Customer Accounting	0	(69)	(69)	0	(69)
13	Customer Service & Info	60,015	(1,575)	58,440	0	58,440
14	Uncollectibles	8,198	0	8,198	104	8,302
15	Administrative and General	109,785	(12,876)	96,909	0	96,909
16	**Total Operation & Maintenance**	$1,177,769	($43,369)	$1,134,400	$104	$1,134,504
17	Depreciation	$154,384	$0	$154,384	$0	$154,384
18	Amortization	18,848	0	18,848	0	18,848
19	Taxes Other than Income	47,497	(2,267)	45,230	0	45,230
20	Income Taxes	30,758	15,985	46,743	7,501	54,244
21	Miscellaneous Revenue and Expense(Franch. Fees)	36,193	0	36,193	460	36,653
22	**Total Operating Expenses**	$1,465,449	($29,651)	$1,435,798	$8,065	$1,443,863
23	**Net Operating Revenues**	$98,986	$31,339	$130,342	11,609	$141,951
24	**Average Rate Base**					
25	Electric Plant in Service	$4,316,780	($9,300)	$4,307,480	$0	$4,307,480
26	Less: Accumulated Depreciation & Amortization	(2,463,112)	0	(2,463,112)	0	(2,463,112)
27	Accumulated Deferred Income Taxes	(205,677)	0	(205,677)	0	(205,677)
28	Accumulated Deferred Inv. Tax Credit	(5,005)	0	(5,005)	0	(5,005)
29	**Net Utility Plant**	$1,642,986	($9,300)	$1,633,686	$0	$1,633,686
30	Plant Held for Future Use	$0	$0	$0	$0	$0
31	Acquisition Adjustments	0	0	0	0	0
32	Working Capital	76,203	(1,542)	74,661	419	75,081
33	Fuel Stock	0	0	0	0	0
34	Materials & Supplies	50,177	0	50,177	0	50,177
35	Customer Advances for Construction	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0
37	Misc Deferred Credits	(28,082)	0	(28,082)	0	(28,082)
38	Misc. Deferred Debits	4,689	0	4,689	0	4,689
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0
40	**Total Average Rate Base**	$1,745,973	($10,842)	$1,735,131	$419	$1,735,550
41	**Rate of Return**	5.67%		7.51%		**8.18%**
42	**Implied Return on Equity**	4.86%		8.45%		9.80%

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	SUMMARY SHEET	Company's Change for Port Westward (6)	Results with Port Westward Change (7)	Adjustments Impacting only Port Westward (8)	Adjusted for Port Westward Change (9)	Revenue Req with Port Westward 3/31/2007 (10)	Results with Port Westward 3/1/2007 (11)
1	**Operating Revenues**						
2	Retail Sales	$0	$1,566,373	$0	$1,566,373	$38,467	$1,604,840
3	Wholesale Sales	0	0	0	$0	0	0
4	Other Revenues	0	19,416	0	$19,416	0	19,416
5	**Total Operating Revenues**	$0	$1,585,789	$0	$1,585,789	$38,467	$1,624,256
6	**Operating Expenses**						
7	Net Variable Power Costs	($11,746)	$818,384	$0	$818,384	$0	$818,384
8	Production	8,440	80,056	0	80,056	0	80,056
9	Other Power Supply (Trojan)	0	218	0	218	0	218
10	Transmission	0	10,245	0	10,245	0	10,245
11	Distribution	0	58,713	0	58,713	0	58,713
12	Customer Accounting	0	(69)	0	(69)	0	(69)
13	Customer Service & Info	0	58,440	0	58,440	0	58,440
14	Uncollectibles	0	8,302	0	8,302	204	8,506
15	Administrative and General	315	97,224	0	97,224	0	97,224
16	**Total Operation & Maintenance**	($2,991)	$1,131,513	$0	$1,131,513	$204	$1,131,717
17	Depreciation	$10,667	$165,050	($1,988)	$163,062	$0	$163,062
18	Amortization	0	18,848	0	18,848	0	18,848
19	Taxes Other than Income	0	45,230	0	45,230	0	45,230
20	Income Taxes	**(6,217)**	48,027	343	48,370	14,670	63,040
21	Miscellaneous Revenue and Expense(Franch. Fees)	0	36,653	0	36,653	900	37,553
22	**Total Operating Expenses**	$1,459	$1,445,327	($1,645)	$1,443,682	$15,774	$1,459,456
23	**Net Operating Revenues**	($1,459)	$140,492	$1,645	$142,137	$22,708	$164,845
24	**Average Rate Base**						
25	Electric Plant in Service	$285,205	$4,592,685	$994	$4,593,679	$0	$4,593,679
26	Less: Accumulated Depreciation & Amortization	(5,333)	(2,468,445)	0	(2,468,445)	0	(2,468,445)
27	Accumulated Deferred Income Taxes	(1,758)	(207,435)	0	(207,435)	0	(207,435)
28	Accumulated Deferred Inv. Tax Credit	0	(5,005)	0	(5,005)	0	(5,005)
29	**Net Utility Plant**	$278,114	$1,911,800	$994	$1,912,794	$0	$1,912,794
30	Plant Held for Future Use	$0	$0	$0	$0	$0	$0
31	Acquisition Adjustments	0	0	0	0	0	0
32	Working Capital	76	75,157	(86)	75,071	820	75,891
33	Fuel Stock	0	0	0	0	0	0
34	Materials & Supplies	0	50,177	0	50,177	0	50,177
35	Customer Advances for Construction	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0
37	Misc Deferred Credits	0	(28,082)	0	(28,082)	0	(28,082)
38	Misc. Deferred Debits	0	4,689	0	4,689	0	4,689
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0
40	**Total Average Rate Base**	$278,190	$2,013,740	$908	$2,014,648	$820	$2,015,468
41	**Rate of Return**		8.18%		7.06%		**8.18%**
42	**Implied Return on Equity**		9.80%		7.53%		9.80%

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	Income Tax Calculations	2007 Per Company Filing (1)	Staff Proposed Adjustments (2)	2007 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$1,564,435	$1,688	$1,566,123	$19,666	$1,585,789
2	Book Expenses Other than Depreciation	1,280,307	(45,636)	1,234,671	564	1,235,235
3	State Tax Depreciation	154,384	0	154,384	0	154,384
4	Interest	51,097	6,648	57,745	14	57,759
5	Less: Schedule M Differences	(38,410)	0	(38,410)	0	(38,410)
6	State Taxable Income	$117,057	$40,676	$157,733	$19,087	$176,820
7	Production Deduction	($4,017)	$0	($4,017)	$0	($4,017)
8	Total State Taxable Income	$113,040	$40,676	$153,716	$19,087	$172,803
9	State Income Tax @ 6.617%	$7,480	$2,691	$10,171	$1,263	$11,434
10	State Tax Credits	(166)	0	(166)	0	(166)
11	Net State Income Tax	$7,314	$2,691	$10,005	$1,263	$11,268
12	Additional Tax Depreciation	0	0	0	0	0
13	Plus: Other Schedule M Differences	0	0	0	0	0
14	Federal Taxable Income	$105,726	$37,985	$143,711	$17,824	$161,535
15	Federal Tax @ 35%	$37,004	$13,294	$50,298	$6,238	$56,536
16	Federal Tax Credits	0	0	0	0	0
17	Current Federal Tax	$37,004	$13,294	$50,298	$6,238	$56,536
18	ITC Adjustment					
19	Deferral	0	0	0	0	0
20	Restoration	1,461	0	1,461	0	1,461
21	Total ITC Adjustment	($1,461)	$0	($1,461)	$0	($1,461)
22	Provision for Deferred Taxes	($12,099)	$0	($12,099)	$0	($12,099)
23	Total Income Tax	$30,758	$15,985	$46,743	$7,501	$54,244

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	Income Tax Calculations	Impact of Port Westward (6)	Results with Port Westward Change (7)	Adjustments Impacting Only Port Westward (8)	Adjusted for Port Westward Change (9)	Revenue Req with Port Westward 3/31/2007 (10)	Results at Reasonable Return (11)
1	Book Revenues	$0	$1,585,789	$0	$1,585,789	$38,467	$1,624,256
2	Book Expenses Other than Depreciation	7,676	1,242,911	0	1,242,911	1,104	$1,244,015
3	State Tax Depreciation	0	154,384	(1,988)	152,396		$152,396
4	Interest	8,141	65,900	1,116	67,016	27	$67,043
5 Less:	Schedule M Differences	8,947	(29,463)	0	(29,463)	0	($29,463)
6	State Taxable Income	($24,764)	$152,056	$872	$152,928	$37,328	$190,257
7	Production Deduction	$0	($4,017)	$0	($4,017)	$0	($4,017)
8	Total State Taxable Income	($24,764)	$148,039	$872	$148,911	$37,328	$186,240
9	State Income Tax @ 6.617%	($1,639)	$9,795	$58	$9,853	$2,470	$12,323
10	State Tax Credits	0	(166)	0	(166)	0	(166)
11	Net State Income Tax	($1,639)	$9,629	$58	$9,687	$2,470	$12,157
12	Additional Tax Depreciation	0	0	0	0	0	0
13 Plus:	Other Schedule M Differences	0	0	0	0	0	0
14	Federal Taxable Income	($23,125)	$138,410	$814	$139,224	$34,858	$174,083
15	Federal Tax @ 35%	($8,094)	$48,442	$285	$48,727	$12,200	$60,927
16	Federal Tax Credits	0	0	0	0	0	0
17	Current Federal Tax	($8,094)	$48,442	$285	$48,727	$12,200	$60,927
18	ITC Adjustment						
19	Deferral	0	0	0	0	0	0
20	Restoration	0	1,461	0	1,461	0	0
21	Total ITC Adjustment	$0	($1,461)	$0	($1,461)	$0	$0
22	Provision for Deferred Taxes	$3,516	($8,583)	$0	($8,583)	$0	$3,516
23	Total Income Tax	($6,217)	$48,027	$343	$48,370	$14,670	$63,040

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	Staff Adjustments	All Other Taxes (S-1)	FIT & SIT Adjustment (S-2)	A&G and O&M Adjustment (S-3)	Power Cost Adjustment (S-4)	Incentive Adjustment (S-5)	Wages & Salary Adjustment (S-6)	Coal Loss Adjustment (S-7)	Other Revenues Adjustment (S-8)	Capital Expenditures Adjustment (S-9)	Extrinsic Value Adjustment (S-10)	System Losses Adjustment (S-11)
1	**Operating Revenues**											
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	0	0	0	0	0	0	0	40	0	0	0
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$40**	**$0**	**$0**	**$0**
6	**Operating Expenses**											
7	Net Variable Power Costs	$0	$0	$0	($12,847)	$0	$0	$0	$0	$0	($13,991)	0
8	Production	0	0	0	0	0	0	(354)	0	0	0	0
9	Other Power Supply (Trojan)	0	0	0	0	0	0	0	0	0	0	0
10	Transmission	0	0	(34)	0	0	0	0	0	0	0	0
11	Distribution	0	0	(1,623)	0	0	0	0	0	0	0	0
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0
13	Customer Service & Info	0	0	0	0	0	0	0	0	0	0	0
14	Uncollectibles	0	0	0	0	0	0	0	0	0	0	0
15	Administrative and General	0	0	(4,894)	0	(4,366)	(3,534)	0	0	0	0	0
16	**Total Operation & Maintenance**	**$0**	**$0**	**($6,551)**	**($12,847)**	**($4,366)**	**($3,534)**	**($354)**	**$0**	**$0**	**($13,991)**	**$0**
17	Depreciation	0	0	0	0	0	0	0	0	0	0	0
18	Amortization	0	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	(2,267)	0	0	0	0	0	0	0	0	0	0
20	Income Taxes	892	(2,752)	2,577	5,054	1,734	1,404	139	16	91	5,505	0
21	Miscellaneous Revenue and Expense											
22	**Total Operating Expenses**	($1,375)	($2,752)	($3,974)	($7,793)	($2,632)	($2,130)	($215)	$16	$91	($8,486)	$0
23	**Net Operating Revenues**	**$1,375**	**$2,752**	**$3,974**	**$7,793**	**$2,632**	**$2,130**	**$215**	**$24**	**($91)**	**$8,486**	**$0**
24	**Average Rate Base**											
25	Electric Plant in Service	0	0	0	0	(1,271)	(1,029)	0	0	(7,000)	0	0
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0	0
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	$0	$0	$0	$0	($1,271)	($1,029)	$0	$0	($7,000)	$0	$0
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0
32	Working Capital	(72)	(143)	(207)	(405)	(137)	(111)	(11)	1	5	(441)	0
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	0	0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0
40	**Total Average Rate Base**	**($72)**	**($143)**	**($207)**	**($405)**	**($1,408)**	**($1,140)**	**($11)**	**$1**	**($6,995)**	**($441)**	**$0**
41	**Revenue Requirement Effect**	**($2,339)**	**($4,682)**	**($6,761)**	**($13,257)**	**($4,654)**	**($3,766)**	**($366)**	**($41)**	**($815)**	**($14,436)**	**$0**

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	Staff Adjustments	Membership Adjustment (S-12)	Tenant Improvements Adjustment (S-13)	Weatherization Services Adjustment (S-14)	Customer Info and Advertising Adjustment (S-15)	Ancillary Services Adjustment (S-16)	Total Adjustments (Base Rates)
1	**Operating Revenues**						
2	Retail Sales	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	$0
4	Other Revenues	0	0	0	0	1,648	$1,688
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$1,648**	**$1,688**
6	**Operating Expenses**						
7	Net Variable Power Costs	$0	$0	$0	$0	$0	($26,838)
8	Production	0	0	0	0	0	($354)
9	Other Power Supply (Trojan)	0	0	0	0	0	$0
10	Transmission	0	0	0	0	0	($34)
11	Distribution	0	0	0	0	0	($1,623)
12	Customer Accounting	0	0	(69)	0	0	($69)
13	Customer Service & Info	0	0	0	(1,575)	0	($1,575)
14	Uncollectibles	0	0	0	0	0	$0
15	Administrative and General	(82)	0	0	0	0	($12,876)
16	**Total Operation & Maintenance**	**($82)**	**$0**	**($69)**	**($1,575)**	**$0**	**($43,369)**
17	Depreciation	0	0	0	0	0	$0
18	Amortization	0	0	0	0	0	$0
19	Taxes Other than Income	0	0	0	0	0	($2,267)
20	Income Taxes	32	0	27	619	647	$15,985
21	Miscellaneous Revenue and Expense						$0
22	**Total Operating Expenses**	($50)	$0	($42)	($956)	$647	($29,651)
23	**Net Operating Revenues**	**$50**	**$0**	**$42**	**$956**	**$1,001**	**$31,339**
24	**Average Rate Base**						
25	Electric Plant in Service	0		0	0	0	($9,300)
26	Accumulated Depreciation & Amortization	0	0	0	0	0	$0
27	Accumulated Deferred Income Taxes	0	0	0	0	0	$0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	$0
29	**Net Utility Plant**	$0	$0	$0	$0	$0	($9,300)
30	Plant Held for Future Use	0	0	0	0	0	$0
31	Acquisition Adjustments	0	0	0	0	0	$0
32	Working Capital	(3)	0	(2)	(50)	34	($1,542)
33	Fuel Stock	0	0	0	0	0	$0
34	Materials & Supplies	0	0	0	0	0	$0
35	Customer Advances for Construction	0	0	0	0	0	$0
36	Weatherization Loans	0	0	0	0	0	$0
37	Prepayments	0	0	0	0	0	$0
38	Misc. Deferred Debits	0	0	0	0	0	$0
39	Misc. Rate Base Additions/(Deductions)	0	0	0		0	$0
40	**Total Average Rate Base**	**($3)**	**$0**	**($2)**	**($50)**	**$34**	**($10,842)**
41	**Revenue Requirement Effect**	**($85)**	**$0**	**($71)**	**($1,626)**	**($1,691)**	**($54,590)**

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TAX CALCULATIONS TO ADJUSTMENTS BEFORE PORT WESTWARD
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	Income Tax Calculations	All Other Taxes (S-1)	FIT & SIT Adjustment (S-2)	A&G and O&M Adjustment (S-3)	Power Cost Adjustment (S-4)	Incentive Adjustment (S-5)	Wages & Salary Adjustment (S-6)	Coal Loss Adjustment (S-7)	Other Revenues Adjustment (S-8)	Capital Expenditures Adjustment (S-9)	Extrinsic Value Adjustment (S-10)
1	Book Revenues	$0	$0	$0	$0	$0	$0	$0	$40	$0	$0
2	Book Expenses Other than Depreciation	(2,267)	0	(6,551)	(12,847)	(4,366)	(3,534)	(354)	0	0	(13,991)
3	State Tax Depreciation	0	0	0	0	0	0	0	0	0	0
4	Interest	(2)	7,004	(7)	(13)	(47)	(38)	(0)	0	(233)	(15)
5	Schedule M Differences	0	0	0	0	0	0	0	0	0	0
6	State Taxable Income	$2,269	($7,004)	$6,558	$12,860	$4,413	$3,572	$354	$40	$233	$14,006
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	0	0	0	0
8	Total State Taxable Income	$2,269	($7,004)	$6,558	$12,860	$4,413	$3,572	$354	$40	$233	$14,006
9	State Income Tax	$150	($463)	$434	$851	$292	$236	$23	$3	$15	$927
10	State Tax Credits	0	0	0	0	0	0	0	0	0	0
11	Net State Income Tax	$150	($463)	$434	$851	$292	$236	$23	$3	$15	$927
12	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0	0
13	Other Schedule M Differences	0	0	0	0	0	0	0	0	0	0
14	Federal Taxable Income	$2,119	($6,541)	$6,124	$12,009	$4,121	$3,336	$331	$37	$218	$13,079
15	Federal Tax @ 35%	742	(2,289)	2,143	4,203	1,442	1,168	116	13	76	4,578
16	Federal Tax Credits	0	0	0	0	0	0	0	0	0	0
17	Current Federal Tax	$742	($2,289)	$2,143	$4,203	$1,442	$1,168	$116	$13	$76	$4,578
18	**ITC Adjustment**										
19	Deferral	0	0	0	0	0	0	0	0	0	0
20	Restoration	0	0	0	0	0	0	0	0	0	0
21	Total ITC Adjustment	0	0	0	0	0	0	0	0	0	0
22	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	0	0
23	Total Income Tax	$892	($2,752)	$2,577	$5,054	$1,734	$1,404	$139	$16	$91	$5,505

REVENUE REQUIREMENTS EFFECTS OF ADJUSTMENTS

	All Other Taxes (S-1)	FIT & SIT Adjustment (S-2)	A&G and O&M Adjustment (S-3)	Power Cost Adjustment (S-4)	Incentive Adjustment (S-5)	Wages & Salary Adjustment (S-6)	Coal Loss Adjustment (S-7)	Other Revenues Adjustment (S-8)	Capital Expenditures Adjustment (S-9)	Extrinsic Value Adjustment (S-10)
Revenues and Expenses	($2,329)	($4,662)	($6,732)	($13,201)	($4,459)	($3,608)	($364)	($41)	$154	($14,375)
Rate Base	(10)	(20)	(29)	(56)	(195)	(158)	(2)	0	(969)	(61)
Total	($2,339)	($4,682)	($6,761)	($13,257)	($4,654)	($3,766)	($366)	($41)	($815)	($14,436)

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	Income Tax Calculations	System Losses Adjustment (S-11)	Membership Adjustment (S-12)	Tenant Improvements Adjustment (S-13)	Weatherization Services Adjustment (S-14)	Customer Info and Advertising Adjustment (S-15)	Ancillary Services Adjustment (S-16)	**Total Adjustments (Base Rates)**
1	Book Revenues	$0	$0	$0	$0	$0	$1,648	$1,688
2	Book Expenses Other than Depreciation	0	(82)	0	(69)	(1,575)	0	($45,636)
3	State Tax Depreciation	0	0	0	0	0	0	$0
4	Interest	0	(0)	0	(0)	(2)	1	$6,648
5	Schedule M Differences	0	0	0	0	0	0	$0
6	State Taxable Income	$0	$82	$0	$69	$1,577	$1,647	$40,676
7	Add OR Depletion Adjustment-Net	0	0	0	0	0	0	$0
8	Total State Taxable Income	$0	$82	$0	$69	$1,577	$1,647	$40,676
9	State Income Tax	$0	$5	$0	$5	$104	$109	$2,691
10	State Tax Credits	0	0	0	0	0	0	$0
11	Net State Income Tax	$0	$5	$0	$5	$104	$109	$2,691
12	Additional Tax Depreciation	0	0	0	0	0	0	$0
13	Other Schedule M Differences	0	0	0	0	0	0	$0
14	Federal Taxable Income	$0	$77	$0	$64	$1,473	$1,538	$37,985
15	Federal Tax @ 35%	0	27	0	22	515	538	$13,294
16	Federal Tax Credits	0	0	0	0	0	0	$0
17	Current Federal Tax	$0	$27	$0	$22	$515	$538	$13,294
18	**ITC Adjustment**							
19	Deferral	0	0	0	0	0	0	$0
20	Restoration	0	0	0	0	0	0	$0
21	Total ITC Adjustment	0	0	0	0	0	0	$0
								$0
22	Provision for Deferred Taxes	0	0	0	0	0	0	$0
								$0
23	Total Income Tax	$0	$32	$0	$27	$619	$647	$15,985

REVENUE REQUIREMENTS EFFECTS OF ADJUSTMENTS

	System Losses Adjustment (S-11)	Membership Adjustment (S-12)	Tenant Improvements Adjustment (S-13)	Weatherization Services Adjustment (S-14)	Customer Info and Advertising Adjustment (S-15)	Ancillary Services Adjustment (S-16)	Total Adjustments (Base Rates)
Revenues and Expenses	$0	($85)	$0	($71)	($1,619)	($1,696)	($53,088)
Rate Base	0	0	0	0	(7)	5	($1,502)
Total	$0	($85)	$0	($71)	($1,626)	($1,691)	($54,590)

PORTLAND GENERAL ELECTRIC
UE 180
STAFF NARRATIVE SUMMARY AFTER PORT WESTWARD
MARCH 1, 2007

Item	Staff	Issue	Revenue Requirement Effect
		Revenue Requirement on the Company's Filed Results	$44,911
		Proposed Staff Adjustments	
S-ROR B	BC	Rate of Return Staff proposed Cost of Capital Impact after Port Westward Addition	(3,722)
S-PW-1	JJ	FIT and SIT Deduction to adjust interest calculation to Staff's weighted cost of debt.	**($747)**
S-PW-2	CO	Life Estimate Adjustment Adjustment to reflect change of life estimate for Port Westward from 28.5 years to 35 years	**($1,914)**
S*		Revenue Sensitive Costs	(61)
		Total Staff-Proposed Adjustments (Base Rates):	(6,444)
		Staff-Calculated Revenue Requirements Change (Base Rates):	**$38,467**

PORTLAND GENERAL ELECTRIC
UE 180
Adjustments After Port Westward
MARCH 1, 2007
($000)

	Staff Adjustments	FIT & SIT Adjustment (S-PW-1)	Life Estimate Adjustment (S-PW-2)	Total Adjustments (Base Rates)
1	**Operating Revenues**			
2	Retail Sales	$0	$0	$0
3	Wholesale Sales	0	0	$0
4	Other Revenues	0	0	$0
5	**Total Operating Revenues**	**$0**	**$0**	**$0**
6	**Operating Expenses**			
7	Net Variable Power Costs	$0	$0	$0
8	Production	0	0	$0
9	Other Power Supply (Trojan)	0	0	$0
10	Transmission	0	0	$0
11	Distribution	0	0	$0
12	Customer Accounting	0	0	$0
13	Customer Service & Info	0	0	$0
14	Collectibles	0	0	$0
15	Administrative and General	0	0	$0
16	**Total Operation & Maintenance**	**$0**	**$0**	**$0**
17	Depreciation	0	(1,988)	($1,988)
18	Amortization	0	0	$0
19	Taxes Other than Income	0	0	$0
20	Income Taxes	(439)	782	$343
21	Miscellaneous Revenue and Expense			$0
22	**Total Operating Expenses**	($439)	($1,206)	($1,645)
23	**Net Operating Revenues**	**$439**	**$1,206**	**$1,645**
24	**Average Rate Base**			
25	Electric Plant in Service	0	994	$994
26	Accumulated Depreciation & Amortization	0	0	$0
27	Accumulated Deferred Income Taxes	0	0	$0
28	Accumulated Deferred Inv. Tax Credit	0	0	$0
29	**Net Utility Plant**	$0	$994	$994
30	Plant Held for Future Use	0	0	$0
31	Acquisition Adjustments	0	0	$0
32	Working Capital	(23)	(63)	($86)
33	Fuel Stock	0	0	$0
34	Materials & Supplies	0	0	$0
35	Customer Advances for Construction	0	0	$0
36	Weatherization Loans	0	0	$0
37	Prepayments	0	0	$0
38	Misc. Deferred Debits	0	0	$0
39	Misc. Rate Base Additions/(Deductions)	0	0	$0
40	**Total Average Rate Base**	**($23)**	**$931**	**$908**
41	**Revenue Requirement Effect**	**($747)**	**($1,914)**	**($2,661)**

PORTLAND GENERAL ELECTRIC
UE 180
TAX ADJUSTMENTS AFTER PORT WESTWARD
MARCH 1, 2007
($000)

	Income Tax Calculations	FIT & SIT Adjustment (S-PW-1)	Life Estimate Adjustment (S-PW-2)	Total Adjustments (Base Rates)
1	Book Revenues	$0	$0	$0
2	Book Expenses Other than Depreciation	0	0	$0
3	State Tax Depreciation	0	(1,988)	($1,988)
4	Interest	1,116		$1,116
5	Schedule M Differences	0	0	$0
6	State Taxable Income	($1,116)	$1,988	$872
7	Add OR Depletion Adjustment-Net	0	0	$0
8	Total State Taxable Income	($1,116)	$1,988	$872
9	State Income Tax	($74)	$132	$58
10	State Tax Credits	0	0	$0
11	Net State Income Tax	($74)	$132	$58
12	Additional Tax Depreciation	0	0	$0
13	Other Schedule M Differences	0	0	$0
14	Federal Taxable Income	($1,042)	$1,856	$814
15	Federal Tax @ 35%	(365)	650	$285
16	Federal Tax Credits	0	0	$0
17	Current Federal Tax	($365)	$650	$285
18	**ITC Adjustment**			$0
19	Deferral	0	0	$0
20	Restoration	0	0	$0
21	Total ITC Adjustment	0	0	$0
				$0
22	Provision for Deferred Taxes	0	0	$0
				$0
23	Total Income Tax	($439)	$782	$343

REVENUE REQUIREMENTS
EFFECTS OF ADJUSTMENTS

	FIT & SIT Adjustment (S-PW-1)	Life Estimate Adjustment (S-PW-2)	Total Adjustments (Base Rates)
Revenues and Expenses	($744)	($2,043)	($2,787)
Rate Base	(3)	129	$126
Total	($747)	($1,914)	($2,661)

PORTLAND GENERAL ELECTRIC
UE 180
DECEMBER 31, 2007
COST OF CAPITAL AND REVENUE SENSITIVE COSTS
($000)

REVENUE SENSITIVE COSTS	
Company's Case	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00530
Taxes Other - Franchise	0.02340
- Other	
- Resource supplier	
State Taxable Income	0.9713
State Income Tax	0.06427
Federal Taxable Income	0.90703
Federal Income Tax @ 35%	0.31746
ITC	
Current FIT	0.31746
Other	
Total Excise Taxes	0.38173
Total Revenue Sensitive Costs	0.41043
Utility Operating Income	0.58957
Net-to-Gross Factor	1.696155

COST OF CAPITAL - STAFF	% of CAPITAL	COST	WEIGHTED COST
Common Equity	49.50%	9.80%	4.85%
Preferred Stock	0.00%	0.00%	0.00%
Long Term Debt	50.50%	6.59%	3.33%
Total	100.00%		8.18%

CASE: UE 180/UE 181/UE 184
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Direct Testimony

August 9, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Judy Johnson. I am Program Manager of the Rates and Tariffs Section in the Electric and Natural Gas Division at the Public Utility Commission of Oregon. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/501.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am sponsoring the Federal and State Income Tax Adjustment. My testimony also supports staff witness Ms. Schwartz's testimony on Portland General Electric's (PGE) proposal to install advanced metering infrastructure (AMI). Specifically, my testimony addresses whether the company appropriately calculated the components that comprise the proposed $3.7 million in accelerated write-off for existing meters.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/502, consisting of 2 pages.

ISSUE 1, FEDERAL AND STATE INCOME TAXES-

Q. PLEASE DESCRIBE THE ADJUSTMENT YOU ARE SPONSORING.

A. When taxes are calculated for ratemaking purposes, there are several components that are taken into consideration. For purposes of this calculation, I do not change any component except for the weighted average cost of debt, which is used to calculate interest deductions as seen on Staff/502, Johnson/1 and 2.

Q. WHY DO YOU CHANGE THE WEIGHTED AVERAGE COST OF DEBT?

A. I use the weighted average cost of debt as calculated by staff witness Mr. Morgan. It is appropriate to use staff's weighted average cost of debt to recalculate interest in order to be consistent with staff's case.

Q. HOW DOES CHANGING THE WEIGHTED AVERAGE COST OF DEBT CHANGE THE INTEREST CALCULATION?

A. The weighted average cost of debt is multiplied by the company's rate base and the result is a new figure for interest expense that reflects staff's new cost of debt and/or capital structure.

Q. WHAT IS THE RESULT OF USING STAFF'S WEIGHTED AVERAGE COST OF DEBT?

A. The result, on all rate base except Port Westward, is a decrease in State Income Taxes of $464,000 and a decrease in Federal Income Taxes of $2,294,000. The result on Port Westward rate base is a decrease in State Income taxes of $72,000 and a decrease in Federal Income taxes of $356,000.

Q. IS THIS ADJUSTMENT SUBJECT TO CHANGE AT THE CONCLUSION OF THE RATE CASE?

A. Yes. This adjustment should be updated for the Commission-approved weighted average cost of debt at the conclusion of the rate case.

ISSUE 2, AMI ACCELERATED WRITE-OFF

Q. PLEASE EXPLAIN HOW PGE CALCULATED THE $3.7 MILLION REVENUE REQUIREMENT FOR ACCELERATED WRITE-OFF OF EXISTING METERS.

A. The company applied its approved cost of capital and gross-up factor to the applicable meter net rate base and depreciation expense. The $3.7 million revenue requirement in the test year reflects the difference in costs between status quo of the old system revenue requirement and the revenue requirement of the old system as the accelerated depreciation is applied, which would set the net book value of the existing meters to zero by the end of the AMI installation period.

Q. ARE THE COMPONENTS OF THE REQUEST CALCULATED CORRECTLY?

A. Yes.

Q. IF THE COMMISSION APPROVES PGE'S REQUEST FOR ACCELERATED WRITE-OFF OF EXISTING METERS, SHOULD THE AMOUNT INCLUDED IN RATES BE $3.7 MILLION?

A. No. That amount is based on using the cost of capital and gross-up factor approved in UE 115. If the Commission approves PGE's request for accelerated write-off of existing meters, the amount that should be included in rates should be recalculated using the factors approved in this current rate case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 180/UE 181/UE 184
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

August 9, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	JUDY A. JOHNSON
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR REVENUE REQUIREMENTS ANALYST
ADDRESS:	550 CAPITOL ST. N.E., SALEM, OREGON 97310-1380
EDUCATION:	MBA with an emphasis in Statistics from Eastern Washington University Cheney, Washington BA in Accounting from Eastern Washington University Cheney, Washington

EXPERIENCE:

3/95-Present	I have been employed by the Oregon Public Utility Commission since March of 1995. My current position is Program Manager of Rates & Tariffs. I was previously a Senior Analyst for the Revenue Requirements Section.
6/77-2/95	I was employed by Avista Corporation, an electric and natural gas utility located in Spokane, Washington. The majority of my employment was spent in the Rates and Regulatory Affairs Department as a Senior Rate Analyst. I have prepared testimony and exhibits in numerous electric and natural gas rate cases, primarily in the area of results of operations and cost of service.

CASE: UE 180/UE 181/UE 184
WITNESS: Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
of Direct Testimony

August 9, 2006

2007 test period; dollars in 000

Calculates test period income tax for the adjusted results of operations based on the following:
(a) Ratemaking Interest deduction calculated using staff's proposed weighted cost of debt.
(b) Does not include Port Westward.
In Staff's revenue requirement model, the interest effect for individual adjustments will be included in the income tax calculation for each.

State & Federal Income Tax - Twelve months ended December 2007

Line No.	Description	Staff	As Filed	Adjustments
1	Operating Revenues	1,662,352	1,662,352	
2	O&M Expense (Includes Depreciation & Other Taxes)	1,437,502	1,437,502	
3	Interest Deductions	58,175	51,158	
4	Book Taxable Income	166,675	173,692	
5	Production Deduction	4,017	4,017	
6	Temporary Schedule M	(30,787)	(30,787)	
7	Permanent Schedule M	(7,623)	(7,623)	
8	Income Before State Tax	201,068	208,085	
9	State Tax Rate	6.617%	6.617%	
10	State Tax Expense	13,305	13,769	
11	State Tax Credits	(166)	(166)	
12	**Net State Income Tax**	13,139	13,603	**(464)**
13	Taxable Income	187,929	194,482	
14	Federal Tax Rate	35.000%	35.000%	
15	Total Federal Income Tax	65,775	68,069	**(2,294)**
16	ITC Amortization	(1,461)	(1,461)	
17	Deferred Taxes	(12,099)	(12,099)	
18	**Total Income Tax (State, Federal, Defer, & ITC)**	65,354	68,112	**(2,758)**

2007 test period; dollars in 000

Calculates test period income tax for the adjusted results of operations based on the following:
(a) Ratemaking Interest deduction calculated using staff's proposed weighted cost of debt.
(b) Port Westward only.
In Staff's revenue requirement model, the interest effect for individual adjustments will be included in the income tax calculation for each.

State & Federal Income Tax - Twelve months ended December 2007

Line No.	Description	Staff	As Filed	Adjustments
1	Operating Revenues	44,911	44,911	
2	O&M Expense (Includes Depreciation & Other Taxes)	8,665	8,665	
3	Interest Deductions	9,258	8,170	
4	Book Taxable Income	26,988	28,076	
5	Production Deduction	0	0	
6	Temporary Schedule M	8,947	8,947	
7	Permanent Schedule M	0	0	
8	Income Before State Tax	18,041	19,129	
9	State Tax Rate	6.617%	6.617%	
10	State Tax Expense	1,194	1,266	
11	State Tax Credits	0	0	
12	**Net State Income Tax**	1,194	1,266	**(72)**
13	Taxable Income	16,847	17,863	
14	Federal Tax Rate	35.000%	35.000%	
15	Total Federal Income Tax	5,896	6,252	**(356)**
16	ITC Amortization	0	0	
17	Deferred Taxes	0	0	
18	**Total Income Tax (State, Federal, Defer, & ITC)**	7,090	7,518	**(428)**

CASE: UE 180/UE 181/UE 184
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Direct Testimony

August 9, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Lisa Schwartz. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/601.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony addresses two issues in the case: 1) Portland General Electric's (PGE's) proposal to install advanced metering infrastructure (AMI) and 2) issues related to partial requirements service, including a) the proposed new notification requirement for changing Baseline Demand if the customer's request is due to changes in generator capacity or generation operations and b) restrictions related to customer-generator power sales to third parties.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Staff Exhibit 602, responses to selected data requests, consisting of 82 pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

Advanced Metering Infrastructure 2
Partial Requirements Service 30

ADVANCED METERING INFRASTRUCTURE

Q. PLEASE SUMMARIZE THE ISSUE.

A. PGE requests "that the Commission find that the decision to proceed with deployment of an AMI system is reasonable and prudent at this time. We are also asking for Commission approval of the ratemaking treatment we propose for AMI-related costs. This proposal includes a deferral of the revenue requirement for capital costs and O&M savings resulting from AMI installation." *See* PGE/800, Hawke-Carpenter-Tooman/1, Lines 10-15. In addition to its proposal to defer the revenue requirements for the new AMI system, during the 2007-09 AMI installation period the company proposes to accelerate the write-off of the existing meters that would be removed from service.

Q. DO YOU RECOMMEND THAT THE COMMISSION FIND IN UE 180 THAT PGE'S DECISION TO PROCEED WITH AMI IS "REASONABLE AND PRUDENT AT THIS TIME?"

A. No. The Commission does not pre-approve investments in traditional rate case filings. Further, as I describe below, the company did not file the final configuration of the AMI system it plans to install, and testified using only rough estimates of costs and O&M savings.

Q. WHAT ARE THE ESTIMATED CAPITAL COSTS OF THE AMI SYSTEM?

A. The company estimates an initial capital investment of approximately $141 million based on non-binding confidential budgetary quotes from equipment vendors and estimated installation costs. *See* PGE/800, Hawke-Carpenter-Tooman/4. As of the time of filing, the company had not determined the actual system it plans to deploy, based on responses to its Request for Proposals (RFP) for AMI equipment. The company also had not yet issued an RFP for installing the AMI system.

Q. WHAT NET BENEFITS DOES PGE ESTIMATE FOR ITS AMI PROPOSAL?

A. PGE estimates a net present value benefit (reduced revenue requirement) of $4 million for the 20-year period beginning in 2007, assuming NW Natural does not extend its automated (drive-by) meter reading program into the joint meter reading area (and therefore joint *manual* reading would continue if PGE does not install an AMI system). If, however, NW Natural does install an automated system in the joint meter reading area, PGE estimates a net present value benefit of about $20 million. The savings under this scenario are higher because PGE would have to hire more meter readers, with associated costs, absent the joint reading program. *See* PGE/800, Hawke-Carpenter-Tooman/5-6. At least in the near-term, based on NW Natural's responses to Staff data requests described later in my testimony, the first case appears to be the more reasonable assumption.

Ultimately, however, it is unlikely that either company would continue to manually read meters in the joint meter reading area over the full 20-year period, given the trend in the industry toward automation.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE AMI PROPOSAL IN PGE/800?

A. I recommend that:

1) The Commission find that the components that comprise the $3.7 million revenue requirement for accelerated write-off of existing metering capital are appropriately calculated.
2) PGE make a supplemental tariff filing for its proposed accelerated write-off of existing metering capital during the 2007-09 AMI installation period, with a special condition terminating the schedule if PGE does not begin Stage 2 mass deployment of the new meters by January 1, 2008. *See* PGE's response to Staff Data Request No. 357, Staff/602, Schwartz/1. Any salvage value from the retired meters should be used as a reduction to the remaining investment to be recovered through the accelerated depreciation.
3) PGE file its final estimated costs for AMI deployment, based on the results of the company's AMI and third-party installer RFPs and an updated assessment of other AMI-related costs, as well as updates to estimated annual O&M benefits. Staff should review the filing and advise the Commission whether the company's final AMI business case, based largely on competitive bidding results, would be expected to provide net benefits to ratepayers, and therefore whether accelerated write-off of existing metering capital is appropriate.
4) Prior to the Commission making a decision on PGE's tariff for accelerated write-off of existing metering capital, the company file with the Commission detailed implementation plans that would reasonably be expected to achieve the O&M benefits assumed in the company's AMI analysis.

5) PGE file a deferral application and establish a balancing account for the AMI installation period, through December 31, 2009. The deferral account should include the estimated annual O&M savings resulting from the AMI system throughout the deferral period. Staff is still reviewing PGE's estimated savings and will advise the Commission on its findings in surrebuttal testimony or in response to PGE's deferral application. When PGE requests authorization to collect the funds in the deferral balancing account, the company must demonstrate that proceeding with AMI deployment was reasonable and prudent at the time it made its final decision to do so and that the system was prudently installed and implemented.

6) The Commission find reasonable PGE's proposed 20-year net present value methodology for determining whether the AMI system is expected to provide net benefits for customers, considering O&M benefits and AMI system costs. Such costs should include all installed costs of AMI-related equipment as well as all implementation costs for achieving estimated O&M savings. Because the company makes no demand response commitments in the rate case, the company's cost-benefit analysis for its AMI proposal relies solely on O&M savings unrelated to demand response.

7) The Commission require PGE to coordinate its AMI installation with NW Natural such that NW Natural has a reasonable opportunity to install an automated meter reading system in the joint meter reading area to avoid

incremental manual reading costs, if an AMI system to continue joint meter reading is not feasible or economic for the companies.

PGE's AMI Proposal Generally

Q. WHAT IS AMI?

A. PGE describes it as follows:

> AMI is a system that enables the automated collection of meter data via a fixed network. A complete AMI system consists of solid-state electronic meters; a communication system, or network, to transmit the data; and a communication server or computer system that receives and stores data from the meter, and as a two-system, sends commands to the meter. This two-way capability enables the utility to send commands to the meter or control devices at the customers' premises. *See* PGE/800, Hawke-Carpenter-Tooman/2, Lines 2-7.

Q. PLEASE DESCRIBE PGE'S PROPOSED AMI SYSTEM.

A. To accommodate the various regions PGE serves and the most cost-effective solution, the company assumes it will install three types of advanced meters, each using a different communication scheme: 1) power-line carrier (PLC) 2) radio frequency (RF) and, in rare cases where RF or PLC technology would not be effective, 3) phone. The meters come pre-programmed and ready to install from the factory. The installer records old and new meter reads and associated identifiers. With the exception of an electronic work order process, installation would be identical to the company's current meter exchange processes. *See* PGE's responses to Staff Data Request Nos. 349-351, Staff/602, Schwartz/2-4.

Associated with the PLC and RF meters are PLC and RF networks. The company also proposes to install hardware and software for data collection, storage and processing, and interfaces with other PGE systems. The types of equipment and systems the company actually would install will be based on its review of vendor bids.

Data from each meter will be received by the company's Meter Data Consolidator which takes in data from a wide variety of meter types, including standard mechanical meters as well as solid-state RF and phone meters the company already has installed. The Meter Data Consolidator is the system of record for all PGE meter read data, providing validated data for customer billing. *See* PGE/800, Hawke-Carpenter-Tooman/8-9.

Q. DOES PGE PLAN TO REPLACE ALL OF ITS METERS?

A. Yes, except for some specialized meters for its largest customers. In all, the company assumes deployment of some 843,000 AMI meters. *See* PGE/800, Hawke-Carpenter-Tooman/8.

That includes most of the interval meters PGE installed for medium-size and larger nonresidential customers to enable direct access, following the company's last general rate case (UE 115). Also at that time, the company installed some 12,300 advanced meters to test their capability and 3,600 such meters for rural routes on Mount Hood to reduce meter reading costs. *See* PGE's response to CUB Data Request No. 4.d., Staff/602, Schwartz/5-6.

PGE proposes to replace any meters that do not have capability to record usage by time of day, as well as some 35,000 nonresidential solid-state meters that have time of use capability, but cannot store interval data (e.g., in hourly or 15-minute increments). Unless the time of use meters can be retrofitted to accommodate the selected AMI systems, PGE proposes to replace them because of the high cost to manually read the meters and to reprogram the time periods if a time-of-use program changes. PGE further states that such meters would not support critical peak pricing. *See* PGE's response to Staff Data Request No. 507, Staff/602, Schwartz/7.

Other meters will be replaced where there is a short payback for doing so, due to avoidance of monthly communication charges (i.e., telephone or pager) to transmit the meter data or to avoid having to replace batteries. The new meters PGE is considering do not require a battery. *See* PGE's response to Staff Data Request No. 508, Staff/602, Schwartz/8-9.

Q. PLEASE DESCRIBE THE INSTALLATION PROCESS.

A. PGE plans two stages of AMI deployment. About 22,000 meters will be installed for Stage 1 system acceptance tests beginning late 2006 or early 2007. Pending successful completion of these tests, Stage 2 mass deployment of approximately 820,000 meters is expected to begin third quarter of 2007 and continue for about 24 months into 2009.

PGE plans to hire a third-party contractor to install most of the meters. The company planned to issue an RFP in June 2006 to solicit bids for meter installation, with execution of a contract possible by October 2006. The company plans to install itself the radio frequency collectors and all primary metered locations. *See* PGE's responses to Staff Data Request Nos. 349-351 and 356-357, Staff/602, Schwartz/1-4, 10.

Q. WHY DOES PGE PROPOSE TO INVEST IN AMI AT THIS TIME?

A. PGE proposes to implement an AMI system to reduce operational costs in the long term, provide customers with better services, enable demand response programs and provide more accurate and timely billing. PGE further states that the time is right for two reasons: 1) the technology is mature, with deployment of systems throughout the West Coast, and 2) grid management and demand response goals cannot be achieved without AMI. The company cites Commission interest in these goals, as well as the Smart Metering requirements in the Energy Policy Act of 2005, which require the Commission to consider providing this technology as well as time-varying pricing options, or load reduction credits, to all customers.[1] *See* PGE/800, Hawke-Carpenter-Tooman/2-4.

PGE further states that costs for AMI technologies are stable. The company points out that PLC system costs have not changed significantly in the last six years, and PGE does not expect a significant change in the future because advances in electronics cannot bring down the cost of safely interfacing communications at the meter end-point and at the substation. While PGE notes that the cost of two-way radio-based communications has decreased 10 percent to 20 percent in the past five years, it does not expect that trend to continue. PGE further does not expect many new entrants in the AMI technology field in the next five years. Regardless, the company states it would only consider proposals from well-established companies in good financial standing. Finally, PGE sees several barriers to further development in the next five years of emerging AMI technologies such as Internet-based metering or Broadband over Power Line communications. *See* PGE's response to Staff Data Request No. 429, Staff/602, Schwartz/11-13.

Q. WHAT HAPPENS TO THE METER READERS EMPLOYED BY THE COMPANY?

A. PGE does not plan to provide employment guarantees for meter readers that will no longer be required if the company installs the proposed AMI system. Severance payouts for these meter readers are included in the AMI cost assumptions. Open meter reader positions in the near-term will be hired on a temporary basis to meet PGE's interim needs. *See* PGE's response to Staff Data Request No. 438, Staff/602, Schwartz/14.

AMI Costs

Q. WHAT AMI SYSTEM COSTS ARE INCLUDED?

A. As discussed above, estimated capital costs are roughly $141 million, including equipment and installation. Table 1 in PGE/800 provides an estimated cost breakdown by category (type of meter, system development, network equipment, etc.). *See* PGE/800, Hawke-Carpenter-Tooman/4, and PGE's

[1] Staff expects to address these Energy Policy Act requirements in Docket UM 1188, an investigation into policies that facilitate advanced metering to improve demand response capabilities.

response to Staff Data Request No. 374-Attachment I (correcting annual totals in Table 1 in PGE/800), Staff/602, Schwartz/15-16.

Q. ARE STATE INCENTIVES AVAILABLE TO REDUCE THE COST OF PGE'S PROPOSED AMI SYSTEM?

A. Possibly. PGE plans to explore incentives available through the Oregon Business Energy Tax Credit program, but has not yet applied for certification for the AMI project. Under the program, a total of 35 percent of the certified cost of a project applies against state income tax liability over a five-year period, with carry-forward provisions up to an additional eight years. Eligible project costs are limited to $10 million. PGE states that any tax savings available under the program could be deferred for future refund to customers. *See* PGE's responses to Staff Data Request Nos. 385-386, Staff/602, Schwartz/17-18. It is unclear whether any AMI expenses would be eligible for the program.

AMI Savings

Q. WHAT ARE THE ANNUAL O&M SAVINGS PGE ASSUMES FOR RATEPAYERS?

A. PGE estimates some $17.1 million to $18.7 million in O&M savings in 2010, depending on assumptions about NW Natural's automated meter reading program. The savings are primarily in labor (mainly fewer meter readers and field collectors), Energy Unaccounted For, Late Fees and Power Cost Savings. *See* Table 2, PGE/800, Hawke-Carpenter-Tooman/6.

Q. DOES PGE PROPOSE TO INCLUDE REMOTE DISCONNECT/ RECONNECT TECHNOLOGY?

A. Yes, for all rental residences. Based on an analysis of service disconnect records, PGE found that 60 percent to 70 percent of service disconnections occur at residential, non-owner occupied residences. PGE initially estimates some 235,000 installations of remote disconnect/reconnect technology. Installing this technology at the time AMI is installed can reduce costs.

Q. WHAT ARE THE ESTIMATED COSTS AND SAVINGS ASSOCIATED WITH REMOTE DISCONNECTION/RECONNECTION?

A. PGE estimates an incremental cost of $26.3 million for the hardware, installed, plus about $2 million to design the process and implement the remote disconnect/reconnect system.

PGE estimates the technology would reduce by about two-thirds the full-time employees performing disconnections. Other savings come from enabling disconnection at an earlier date, within Commission rules. Currently, the company may defer disconnections in order to justify the expense of a site visit. PGE estimates some $6.5 million will be collected on average 50 days earlier. The associated reduction in working capital would reduce annual revenue requirements.

In addition, PGE estimates that earlier disconnects would reduce annual power costs by about $1.2 million because of the reduced energy delivered. Further, PGE estimates that with automated disconnection when a tenant moves out, power costs could be reduced by some $100,000 per year. This represents the 20,000 rental properties per year where a tenant moves out and the landlord has not agreed to pay for the energy that continues to be delivered to the residence. *See* PGE's response to Staff Data Request No. 382, Staff/602, Schwartz/19-21.

Q. WHAT ADDITIONAL BENEFITS HAS PGE IDENTIFIED, AND HOW DOES THE COMPANY PLAN TO ACQUIRE THEM?

A. PGE has identified additional benefits including those related to demand response, the transmission and distribution system, and added functionality for customers. Of these, however, PGE has developed a timeline and estimated costs and benefits only for customer-selected due date (where a customer can choose the date payment is due). PGE estimates the IT costs to develop the program at roughly $1.5 million, and benefits in reduced Working Cash rate base of about $5 million annually. See PGE's response to Staff Data Request No. 363, Staff/602, Schwartz/22-23.

Q. HAS PGE SPECIFICALLY IDENTIFIED ALL OF THE COST SAVINGS THAT CAN BE ACHIEVED WITH AMI?

A. No. PGE notes that AMI can enable additional programs that reduce costs, including demand response programs, outage reporting, outage detection, restoration, and better distribution planning. However, the company has not identified the potential savings associated with these programs, nor has it developed implementation plans. *See* PGE/800, Hawke-Carpenter-Tooman/10; PGE's responses to Staff Data Request Nos. 364-369, Staff/602, Schwartz/24-29.

I address potential demand response benefits below. In Exhibit 700, Staff witness Gonzalez provides testimony on other programs for which PGE has not developed savings estimates.

Q. WHY DO YOU RECOMMEND PGE FILE IMPLEMENTATION PLANS FOR ACHIEVING SAVINGS RESULTING FROM THE PROPOSED AMI SYSTEM?

A. The savings may not be achieved, or acquired in full, in the absence of appropriate implementation plans. Staff witness Gonzalez provides supporting testimony on this issue in Exhibit 700.

Q. WOULD AMI FACILITATE DEMAND RESPONSE?

A. Yes. AMI is enabling technology for a variety of demand response programs, including time-varying pricing, direct load control and customer curtailment programs — all of which could reduce costs for PGE and provide individual customer savings. Generally, once an AMI system is installed, the cost of demand response programs is reduced.

The AMI system would collect interval meter data (e.g., usage each hour) needed to support standard time of use pricing, as well as critical peak pricing and real time pricing, and would allow changes to rate design without costly reprogramming of time periods at the meter site.

AMI also provides the communications system necessary for direct load control by the *utility*, or to send a signal to a business's energy management system or a homeowner's thermostat with customer-determined settings for automated control by the *customer*. A two-way AMI system also provides verification of customer load reductions. *See* PGE/800, Hawke-Carpenter-Tooman/10; PGE's responses to Staff Data Request Nos. 360-361, Staff/602, Schwartz/30-32.

Q. ARE CUSTOMERS TYPICALLY *REQUIRED* TO PARTICIPATE IN THESE DEMAND RESPONSE PROGRAMS?

A. No, except it is common for the largest customers to have mandatory time-varying rates. For example, standard cost of service rates for PGE's and Pacific Power's largest customers are slightly higher during on-peak hours than in off-peak hours.

Q. WHAT ARE SOME EXAMPLES OF VOLUNTARY DEMAND RESPONSE OPTIONS THAT AMI CAN ENABLE?

A. A time of use rate is one of the choices residential and small nonresidential customers have under the state's electric industry restructuring law. AMI can enable improved rate design, through critical peak pricing in conjunction with "smart" thermostats. Residential customers also voluntarily participated several years ago in PGE's pilot programs to test direct load control of water heating and space heating, and PacifiCorp runs a successful air-conditioning load control program in Utah. Neither utility offers load control programs in Oregon today. AMI can reduce the cost of offering such programs.

Both utilities have programs in Oregon for large customers that receive payment for curtailing load upon request. The programs have been largely inactive since 2001, but were exercised recently to respond to extreme summer weather. Medium-size commercial and industrial customers have no demand response programs to choose from. AMI can make it more cost-effective to offer these customers critical peak pricing and load curtailment programs.

Q. DOES PGE MAKE ANY DEMAND RESPONSE COMMITMENTS IN THIS RATE CASE?

A. No. PGE's proposal is to make a business case for AMI absent demand response benefits, and the company makes no demand response commitments in the rate case. Therefore, the Commission should not consider demand response benefits when determining whether the company has made the business case in UE 180 for investing in AMI.

Q. HOW DOES PGE INTEND TO REVIEW DEMAND RESPONSE PROGRAMS THAT COULD MAKE USE OF THE AMI SYSTEM?

A. PGE is planning to include demand response resources in its 2006 Integrated Resource Plan. *See* PGE's response to Staff Data Request No. 363, Staff/602, Schwartz/22-23. The company intends to file the plan by the end of the year.

Estimating the Net Benefits

Q. PLEASE EXPLAIN THE METHODOLOGY PGE USED TO ESTIMATE NET BENEFITS TO RATEPAYERS FROM ITS PROPOSED AMI INVESTMENT.

A. PGE calculated the net present value of reduced revenue requirements resulting from AMI over a 20-year period. (Net present value calculations take into account the time value of money.)

Q. WHY DO YOU FIND THIS METHODOLOGY REASONABLE?

A. AMI is a long-term investment. It therefore is appropriate to take into account the long-term reduction in costs the company expects to achieve from AMI. Net present value of revenue requirements over a 20-year period is used in Integrated Resource Planning, for example, to compare portfolio options with various combinations of generation and transmission resources. Further, the 20-year period reasonably matches the assumed depreciation life of the new meters.

Q. WHAT DEPRECIATION LIFE IS PGE PROPOSING TO USE FOR THE NEW METERS THAT WOULD BE INSTALLED UNDER THE AMI PROPOSAL?

A. PGE plans to use 18-year meter lives for all three meter types (power line carrier, radio frequency and phone). PGE selected this depreciation rate based on the 15- to 20-year design life of a solid-state induction meter, the company's meter shop statistics for solid-state meters, and other factors. *See* PGE's responses to Staff Data Request Nos. 437 and 464, Staff/602, Schwartz/33-34.

Accelerated Write-Off of Existing Meters

Q. WHY DOES PGE PROPOSE TO ACCELERATE THE WRITE-OFF OF EXISTING METERING CAPITAL DURING THE AMI INSTALLATION PERIOD?

A. PGE explains that it "proposes to accelerate the depreciation of existing metering capital so that the net book value of those meters is zero by the time the proposed AMI system is fully deployed. According to the Oregon Court of

Appeals decision in CUB v. OPUC, 154 Or. App. 702, 962 P.2d 744, the Commission cannot set rates that include a return on assets retired with an undepreciated balance." In other words, PGE is proposing to fully depreciate the meters that would be removed from service while they are still used and useful as a group asset. PGE further states that if the Commission denies the proposed accelerated write-off, the company would not pursue AMI at this time. *See* PGE's response to Staff Data Request No. 378, Staff/602, Schwartz/35.

Q. WHAT IS THE ESTIMATED IMPACT OF ACCELERATED WRITE-OFF OF EXISTING METERING CAPITAL ON TEST YEAR REVENUE REQUIREMENTS?

A. The company states that its proposed accelerated write-off of existing metering capital would increase PGE's revenue requirement for the test year by approximately $3.7 million. *See* PGE/800, Hawke-Carpenter-Tooman/7.

Q. DID PGE INCLUDE THIS AMOUNT IN ITS RATE REQUEST AND NOTICE TO CUSTOMERS?

A. No.

Q. DOES THIS LACK OF NOTICE RAISE A LEGAL ISSUE?

A. Yes. PGE did not provide proper notice of this $3.7 million request. Further, it is not good policy to allow a utility to file testimony requesting a rate increase that is different, and in fact larger, than that specified by the tariff. Accordingly, staff recommends the Commission decline PGE's request to add $3.7 million to test year revenue requirements unless the company makes a supplemental filing to do so. In addition, in the absence of such a filing, the Commission would not be able to include the $3.7 million in rates unless it adjusts the company's requested rate increase by at least $3.7 million.

Q. PLEASE DESCRIBE PGE'S PROPOSED RETIREMENT SCHEDULE.

A. PGE states that because meters are a group asset, they will be removed from rate base in groups. In the month following replacement, PGE will accelerate depreciation on the meters removed from service so that their net book value is reduced to zero. *See* PGE's response to Staff Data Request No. 461, Staff/602, Schwartz/36.

Q. HOW DID PGE CALCULATE THE $3.7 MILLION REVENUE REQUIREMENT FOR ACCELERATED WRITE-OFF OF EXISTING METERS?

A. Staff witness Johnson describes the calculation in Staff/500, Johnson/3-4.

Q. DOES PGE INCLUDE SALVAGE VALUE FOR THE METERS THAT WOULD BE RETIRED UNDER THE AMI PROPOSAL?

A. No. For retired mechanical meters, PGE has determined that there is little or no market value. The company expects at best to sell them for a few cents per meter as scrap metal. PGE expects to sell the retired solid-state meters for a total of about $20,000. The utility states that the actual revenue could be lower as increasing numbers of used solid-state meters enter the market. *See* PGE's response to Staff Data Request No. 463, Staff/602, Schwartz/37. Any salvage value from the retired meters should be used as a reduction to the remaining investment to be recovered through the accelerated depreciation.

Q. IS THE $3.7 MILLION PGE PROPOSES IN ACCELERATED DEPRECIATION FOR THE TEST YEAR A RECURRING EXPENSE FOR EACH YEAR DURING THE INSTALLATION PERIOD?

A. Yes. The $3.7 million represents the recurring, incremental revenue requirement each year during the AMI deployment period (2007-09). PGE adjusted retirement rates to allow a consistent $3.7 million rate impact in each of the three years. *See* PGE's responses to Staff Data Request Nos. 430 and 462, Staff/602, Schwartz/38-39.

Q. HOW DOES PGE PROPOSE TO ALLOCATE THE REVENUE REQUIREMENTS FOR THE ACCELERATED WRITE-OFF?

A. PGE states that the $3.7 million would be an addition to the distribution revenue requirement for the 2007 test period and would be allocated based on percent of marginal costs in the same manner as other distribution costs are allocated to each rate schedule. *See* PGE's response to Staff Data Request No. 500, Staff/602, Schwartz/40.

Q. WHY DO YOU RECOMMEND PGE MAKE A SUPPLEMENTAL FILING FOR THE ACCELERATED WRITE-OFF OF EXISTING METERING CAPITAL?

A. Staff recommends PGE make a supplemental filing for two reasons. First, the company did not include the proposed $3.7 million in accelerated write-off for existing metering capital in its rate case request. Second, a tariff filing would specify the time period over which the accelerated write-off would occur —

during the company's 2007-09 AMI installation period — and under what conditions the tariff would terminate prior to the scheduled end date.

Q. WHY DO YOU RECOMMEND THAT PGE'S TARIFF INCLUDE A SPECIAL CONDITION TO TERMINATE THE SCHEDULE IF THE COMPANY DOES NOT PROCEED WITH MASS DEPLOYMENT OF NEW METERS BY JANUARY 1, 2008?

A. Accelerated depreciation of existing metering capital is appropriate only if the company actually carries through with the planned installation of the AMI system. In UE 115, the company included installation of Network Meter Reading but the bankruptcy of the selected vendor stymied the completion of the project. *See* PGE's response to CUB Data Request No. 8, Staff/602, Schwartz/41.

Staff's proposed special condition, to terminate accelerated write-off if the company does not carry out the mass deployment of the AMI system after the initial testing period, protects customers against an unnecessary increase in rates in the short term. Even though customers would no longer be paying for the existing meters in rates after their net book value is zero, it would be inappropriate to accelerate depreciation for the remaining meters if they are not going to be replaced with AMI.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT STAFF ADVISE THE COMMISSION AT A LATER DATE WHETHER THE ACCELERATED WRITE-OFF PROPOSAL IS APPROPRIATE?

A. Staff supports accelerated write-off of existing metering capital if the request is properly filed and the company demonstrates a solid AMI business case. The Commission does not yet have a properly filed request or definitive costs and savings on which to judge the business case.

At the time PGE filed its rate case on March 15, 2006, PGE had not selected the equipment vendor(s) and AMI systems based on its RFP issued January 12, 2006. The estimated costs included in PGE's filing are based on non-binding confidential bidder quotes. Further, the company planned to issue in June 2006 an RFP for a third party to install most of the meters. Therefore, PGE's filing does not include a final plan with the types of meters and communication systems the company would be installing, or hardware and installation costs. The type of system installed also could affect assumed O&M savings.

Deferred Accounting for AMI System

Q. PLEASE EXPLAIN PGE'S DEFERRAL PROPOSAL FOR THE CAPITAL COSTS OF THE NEW METERING SYSTEM.

A. PGE requests approval to defer the revenue requirement for capital costs for the AMI system, net of O&M savings resulting from AMI installation. The company estimates the amount of the deferral over the three-year installation period at $21.6 million. *See* PGE/800, Hawke-Carpenter-Tooman/6.

PGE states that it proposes the deferral in order to mitigate the rate increase associated with AMI during the early years of system deployment.

Two primary factors impact revenue requirements in the early years of AMI deployment: 1) accelerated write-off of the existing meters, which must be completed before they are removed from service, and 2) the AMI system becomes "used and useful" as it is being deployed. *See* PGE's response to Staff Data Request No. 432, Staff/602, Schwartz/42.

PGE projects revenue requirement impacts in 2007-09 to be roughly $6.8 million less per year if a deferral is employed (assuming NW Natural would not deploy automated meter reading in the joint reading area absent PGE doing so, and therefore PGE would not be required to hire additional meter readers if the company did not employ AMI, and using the cost of capital and gross-up factor approved in UE 115). *See* "Compare Tab," Attachment 374-B, PGE's response to Staff Data Request No. 374, Staff/602, Schwartz/43-44. How the deferral would impact revenue requirements in subsequent years depends on 1) the deferral balance and 2) the authorized amortization amount and period, determined at a later date.

Q. WHY DO YOU RECOMMEND THAT PGE FILE A DEFERRAL APPLICATION?

A. ORS 757.259(2)(e) requires that the deferral either 1) match the costs and benefits received by ratepayers or 2) minimize the frequency or fluctuations of rate changes. PGE's proposed deferral for AMI capital costs meets both requirements. It matches ratepayer benefits and costs by delaying the inclusion of the new system in rates until it is fully deployed and all ratepayers have the new meters installed and are able to reap the full benefits. In addition, a deferral would minimize rate changes during the AMI deployment period (2007-09) by including AMI costs in rates all at once, after the system is fully deployed.

After determining that an application for deferral qualifies under the statute, the Commission exercises its discretion in determining whether the type of costs in question *should* be deferred. In exercising this discretion, the Commission considers two interrelated factors: the type of event that caused the deferral, and the magnitude of the event's effect. For risks that are reasonably predictable and quantifiable, the Commission has concluded that the magnitude of the financial impact of the event on the utility must be substantial enough to warrant deferral. *See* Order No. 05-1070 at 3; Order No. 04-108 at 9. PGE estimates the impact at $21.6 million over the three-year deferral period.

Further, the Commission has noted its use of a deferral mechanism to encourage utility behavior consistent with regulatory policy. *See* Order No. 05-1070 at 2. The Commission has indicated most recently in AR 500, and previously in adopting Staff's recommendations for demand response, that it wants to encourage utility investment in advanced metering technologies that enable demand response. *See* Order Nos. 03-408 and 06-039.

Q. HOW DOES PGE PROPOSE TO TRACK DEFERRAL ACCOUNT COMPONENTS DURING THE PROPOSED THREE-YEAR DEFERRAL PERIOD?

A. PGE proposes to file a deferral application and establish a balancing account. The balancing account would track the deferred revenue requirement associated with AMI during the deployment period — including capital costs for meters and associated equipment, installation costs, and necessary support systems – net of operating savings during the deferral period. Savings will accrue to the deferral account based on the percent of meters deployed per month. *See* PGE/800, Hawke-Carpenter-Tooman/6-7; PGE's response to Staff Data Request No. 434, Staff/602, Schwartz/45.

Q. WHEN DOES PGE PLAN TO REQUEST THAT THE DEFERRED AMI CAPITAL EXPENSES BE INCLUDED IN RATES?

A. The company expects AMI deployment to be completed in 2009. The economic models PGE used for its AMI business case assume that recovery of the deferral would begin in January 2010. PGE states that it will determine a specific month for submitting an amortization filing subsequent to Commission approval of an AMI deferral mechanism. *See* PGE's response to Staff Data Request No. 436, Staff/602, Schwartz/46.

<u>Joint Meter Reading With NW Natural</u>

Q. PLEASE DESCRIBE THE ISSUE RELATED TO JOINT METER READING WITH NW NATURAL.

A. Where their service areas overlap, PGE and NW Natural have a joint meter reading partnership that reduces meter reading costs for both utilities. Within the area, meter reading routes are optimized and one utility reads both electric and natural gas meters in a single visit.

NW Natural states that based on a preliminary analysis, installation of an automated system to read gas meters in the joint meter reading area is not economic if the joint reading program with PGE continues. *See* NW Natural's response to Staff Data Request No. 4, Staff/602, Schwartz/48.

NW Natural further states that if it alone must perform manual reads in the joint reading area for a period of time — after PGE installs AMI, but before NW Natural could install a drive-by reading system, NW Natural would incur $4.6 million in capital costs and $1.6 million in incremental O&M costs by 2009. *See* NW Natural's response to Staff Data Request No. 1, Staff/602, Schwartz/47, 50-54.

The company could avoid reverting to traditional meter reading routes for any length of time, and minimize the impact of meter route and billing cycle changes on customers, by coordinating with PGE and integrating the conversion schedules of NW Natural's separate installation of an automated system in the joint meter reading area. *See* NW Natural's response to Staff Data Request No. 7, Staff/602, Schwartz/56.

Q. PLEASE DESCRIBE THE AUTOMATED METER READING PROGRAM NW NATURAL IS DEVELOPING *OUTSIDE* THE JOINT METER READING AREA.

A. NW Natural is installing an automated, drive-by meter reading system in areas outside of the joint meter reading area with PGE. The project began in May

2006. NW Natural expects to complete conversion or replacement of 232,676 meters by April 2007. The company estimates annual savings of about $2.3 million in 2008 alone, exclusive of growth. *See* NW Natural's response to Staff Data Request No. 5, Staff/602, Schwartz/48-49.

Q. ARE THERE AMI SYSTEMS THAT COULD ALLOW THE TWO UTILITIES TO CONTINUE JOINT METER READING IN AN AUTOMATED FASHION?

A. NW Natural states that it has not conducted specific analyses to determine whether a joint automated meter reading solution with PGE is feasible, because feasibility is dependent on PGE's choice of technology. However, NW Natural is willing to work with PGE to determine if there is an AMI system capable of cost-effectively reading both companies' meters in the joint meter reading area while performing the functions PGE requires. *See* NW Natural's response to Staff Data Request No. 6, Staff/602, Schwartz/55-56.

PGE states, "Most AMI systems today provide a means for automated data collection of both gas and electric meters. In all cases, automated gas metering is enabled by attaching a special module on the gas meter. The module on the gas meter must have a communication radio that is compatible with the AMI system that PGE selects. In most cases, the gas radio communicates with a device installed in the electric meter. The gas data [would then be] transferred to the field-based collectors owned by PGE using the same communication method PGE uses to collect the electric meter data." PGE notes that collecting data from a large number of gas meters might require installation of additional field-based data collectors.

Some AMI systems would allow NW Natural to collect its data directly from these collectors. Other systems would require collection of both gas and electric meter data in a single computer system, with PGE providing the gas meter data to NW Natural. Altogether, PGE estimates that the incremental costs for its AMI system of accommodating collection of NW Natural meter data at roughly $1 million to $3 million, not including additional hardware in the electric meter. *See* PGE's response to Staff Data Request No. 497, Staff/602, Schwartz/57-59.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION REGARDING JOINT METER READING?

A. I recommend the Commission require PGE to coordinate its AMI installation such that NW Natural has a reasonable opportunity to install an automated system in the joint meter reading area and avoid incremental manual reading costs, if an AMI system to continue joint meter reading is not feasible.

I make this recommendation because if PGE does not provide sufficient notice to NW Natural, or if PGE otherwise fails to coordinate AMI installation with the company, NW Natural could incur incremental manual meter reading costs in the joint meter reading area unnecessarily, because it would have insufficient time to install equipment to enable drive-by reads.

Such a recommendation protects all NW Natural customers, including more than half of them that also are customers of PGE.

PGE states that it expects to collaborate with NW Natural to develop a detailed installation plan that minimizes costs in the joint meter reading area.

See PGE's response to Staff Data Request No. 372, Staff/602, Schwartz/60. The Commission should provide further direction to PGE in its order in UE 180 to avoid unnecessary costs for NW Natural.

PARTIAL REQUIREMENTS SERVICE

Q. PLEASE SUMMARIZE THE ISSUE.

A. PGE proposes to modify Schedules 75 and 575, partial requirements service for cost of service and direct access service, to require two calendar years' notice for requesting a change in Baseline Demand resulting from changes in on-site generation (capacity or operations). The company further proposes that the partial requirements customer be required to wait at least two years before making another such request. *See* PGE/1300, Kuns-Cody/38; PGE/1302, Kuns-Cody/31-37 and 176-180.

Q. WHAT IS BASELINE DEMAND?

A. Baseline Demand is the demand normally supplied by the company when the customer's generator is operating. Baseline Demand is determined by the customer's typical peak demand for the most recent 12 months prior to installing the generator, adjusted for generator operations. The company and customer may mutually agree to use an alternate method to determine Baseline Demand if the customer's demand is highly variable, consistent with the special conditions in the tariff.

Q. HOW DOES BASELINE DEMAND AFFECT THE ENERGY OPTIONS AVAILABLE TO THE SCHEDULE 75 CUSTOMER?

A. Baseline Demand sets the amount of energy eligible for standard cost of service rates, as well as other options available to large customers taking full requirements service, including daily and monthly pricing. (The notification requirements for switching between these options, and to and from service with an alternative supplier, are the same for both partial and full requirements customers.) The amount of this "Baseline Energy" is the energy usage on an hourly basis up to and including the Baseline Demand.

Any energy above this baseline that is not for Scheduled Maintenance of the customer's generating units is Unscheduled Energy, which is priced at an hourly rate based on the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index. The customer also can choose Economic Replacement Power under Schedule 76R, based on the Dow Jones hourly index.

Q. HOW DOES BASELINE DEMAND AFFECT DISTRIBUTION CHARGES?

A. Distribution charges are based in part on Facility Capacity. Facility Capacity is defined as the average of the two greatest non-zero monthly demand levels during the past 12 months, including the current billing period. However, Baseline Demand determines the minimum charge for Facility Capacity.

Q. WHAT DOES PGE MEAN BY TWO CALENDAR YEARS' PRIOR NOTICE?

A. Under PGE's proposal, changes to Baseline Demand due to generation changes "will take effect January 1 of a calendar year at least two years subsequent to the request." For example, a request on July 1, 2007, to change Baseline Demand due to changes in generation would be effective January 1, 2010. *See* PGE's response to Staff Data Request No. 514, Staff/602, Schwartz/61.

Q. PLEASE EXPLAIN PGE'S PROPOSED TWO-YEAR WAITING PERIOD FOR ANY SUBSEQUENT REQUEST TO CHANGE BASELINE DEMAND DUE TO CHANGES IN GENERATION.

A. Under PGE's proposal, any subsequent request to change Baseline Demand, related to changes in generation, "will be granted two years after the previous request for a change in Baseline Demand was granted." Using the previous example of an initial request on July 1, 2007, any subsequent request to change Baseline Demand would not take effect until January 1, 2012. PGE states that the two-year waiting period "maintain[s] the integrity of the notice requirements" and allows the company "to be able to effectively plan for meeting the load requirements of its customers." Further, PGE states that absent this provision, a large customer could frequently attempt to change Baseline Demand by large increments. *See* PGE's responses to Staff Data Request Nos. 404 and 515, Staff/602, Schwartz/62-63.

Q. DO YOU AGREE WITH PGE THAT TWO CALENDAR YEARS' NOTICE FOR CHANGES IN BASELINE DEMAND DUE TO CHANGES IN GENERATOR OPERATIONS "ACHIEVES AN EQUITABLE BALANCING OF INTERESTS BETWEEN ALL OUR CUSTOMERS" (PGE/1300, KUNS-CODY/38)?

A. Staff agrees with PGE that the partial requirements schedules should be modified to provide an extended notification requirement for requests to change Baseline Demand due to changes in generation. However, to achieve an equitable balance of interests, particularly when considering notification requirements for switching to and from alternative energy suppliers, staff recommends three modifications to PGE's proposal.

First, the notification requirement should be modified as follows: A customer request made on or before June 30 of any year to change Baseline Demand due to changes in generating capacity or generation operations will be effective January 1 of the second year following the request. For example, a request made June 30, 2006, would be effective January 1, 2008. For requests made July 1 or after of any year, the change in Baseline Demand will be effective January 1 of the third year following the request. For example, a request made July 1, 2006, would be effective January 1, 2009.

Second, subsequent requests for changes to Baseline Demand should be afforded the same treatment. Meaning, requests received prior to June 30 will be effective January 1 of the second year following the request, and requests received July 1 or after will be effective January 1 of the third year following the request. There should not, as PGE proposes, be a two-year waiting period from the date of the customer's last request.

Third, partial requirements customers should be allowed to make *de minimus* changes in Baseline Demand due to changes in generation without an extended notice requirement. Specifically, staff recommends that a partial requirements customer that changes generator capacity or generation operations be allowed to increase or decrease Baseline Demand within any two-year period by a total of up to 5 megawatts (MW) with only one calendar month's notice. PGE may allow additional such requests for good cause.

Q. PLEASE EXPLAIN WHY YOU GENERALLY AGREE WITH PGE'S PROPOSAL FOR AN EXTENDED NOTIFICATION REQUIREMENT TO

CHANGE BASELINE DEMAND DUE TO CHANGES IN ON-SITE GENERATION.

A. First, staff notes that partial requirements service applies only to customers with generation totaling 1 MW or more, and that such large on-site generation typically is natural gas-fired.

PGE states that without the extended notice requirement a change in Baseline Demand due to changes in on-site generation "would unduly burden other customers or shareholders by allowing the Partial Requirements customer to optimize in the short-term at the expense of others by changing its Baseline Demand based on short-term natural gas market conditions." *See* PGE/1300, Kuns-Cody/38. Staff agrees with PGE in the case of large changes in Baseline Demand.

Under PGE's Resource Valuation Mechanism (RVM), short notice of a change in Baseline Demand for partial requirements customers affects other customers by spreading the economic value of PGE's existing resources over additional kilowatt-hours. If, on the other hand, the change in Baseline Demand is not included in the annual RVM resetting of rates, PGE's earnings would be negatively affected because the benefits of the company's resources included in rates on a kilowatt-hour basis would exceed their total value. *See* PGE's response to ICNU Data Request No. 1.3, Staff/602, Schwartz/64; Staff Report on PGE Advice No. 05-17 for the November 8, 2005, public meeting; Staff Report on PGE Advice No. 05-18 for the December 20, 2005, public meeting.

Extended notification is needed to protect other customers from the rate impacts of customers switching a large amount of load back and forth between the cost of service rate and self-generation, depending on natural gas prices (which affect the economics of on-site generation). Such gaming would put the utility in the position of having to provide additional power on short notice, without the ability to appropriately plan for power supplies.

Q. PLEASE EXPLAIN THE PARALLELS WITH NOTIFICATION REQUIREMENTS FOR CHOOSING AN ALTERNATIVE ENERGY SUPPLIER.

A. Customers that choose PGE's five-year opt-out from cost of service rates (e.g., in order to receive service from an alternative supplier) cannot return to those rates for five years, and they must provide two years' notice to do so. Such notice is binding. *See* PGE Schedule 483, Special Condition 1.

PGE excludes these direct access customers from its resource planning, unless they have provided the two-year notice. Similarly, PGE excludes the on-site load of any partial requirements customer in resource planning, except for the customer's Baseline Demand. PGE states that extended notification requirements are appropriate both for long-term direct access customers and partial requirements customers so they do not have a free option to receive cost of service rates (or receive them for a higher level of demand) when they include transition credits, and to exit cost of service rates when they include transition charges.

Further, direct access customers on the three-year cost of service opt-out have a required service term of three years. PGE states that this serves as a *de facto* three-year notice provision; the company assumes these customers will return to cost of service rates after three years. *See* PGE's responses to Staff Data Request Nos. 408 and 409, Staff/602, Schwartz/65-66.

Q. WHAT ENERGY OPTIONS DOES A SCHEDULE 75 CUSTOMER HAVE WHILE WAITING FOR THE REQUEST TO CHANGE BASELINE DEMAND TO BE EFFECTIVE?

A. The customer would take Economic Replacement Power under Schedule 76R, based on the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index, or select an alternative energy supplier under the provisions of Schedules 575 and 576. *See* PGE's response to Staff Data Request No. 519, Staff/602, Schwartz/67. Also, Schedule 75 customers can take Unscheduled Energy, priced at an hourly rate based on the Dow Jones index, for at least up to 1,000 hours during a calendar year.

Q. PLEASE EXPLAIN WHY STAFF'S PROPOSAL TO ALLOW SMALL ADJUSTMENTS IN BASELINE DEMAND TO ACCOMMODATE MINOR CHANGES IN GENERATION OPERATIONS IS REASONABLE.

A. Customers should be able to request small adjustments to Baseline Demand due to changes in generation without having to wait two years or longer to have the change take effect, and without having to take hourly pricing for the incremental Baseline Demand (or seek service from an alternative supplier). Staff recommends that partial requirements customers be allowed to change

Baseline Demand due to changes in generation up to a total of 5 MW during any two-year period, without extended notice requirements. Changes at or below this level are simply within the noise of the roughly 3,600 MW of peak load PGE serves. *See* PGE Final Action Plan/2002 Integrated Resource Plan, March 2004, p. 26.

As further evidence that 5 MW is a reasonable limit, that is the level of demand that triggers a requirement for the Schedule 75 customer to inform the company within 30 minutes of taking Unscheduled Energy. *See* Special Condition 2. Further, the company has previously stated, “PGE doesn’t specifically notice a customer’s load changes on an individual basis until the swings are in the magnitude of 5 to 10 MW.” *See* letter to Jack Breen, Oregon Public Utility Commission, June 6, 2003, attachment to PGE Advice No. 03-19, filed October 22, 2003.

Q. DOES STAFF’S PROPOSAL TO ALLOW SMALL ADJUSTMENTS TO BASELINE DEMAND TO ACCOMMODATE CHANGES IN GENERATION THREATEN THE INTEGRITY OF PGE’S PROPOSED NOTICE REQUIREMENT?

A. No. Staff’s proposal addresses PGE’s concern about maintaining the integrity of the notice requirement by setting a clear limit on the total demand level (5 MW) that can be changed without an extended notice requirement. Further, with the limit set at 5 MW for a two-year period, staff sees no reason for a customer to constantly put in requests to change Baseline Demand, a concern of PGE's. *See* PGE's response to Staff Data Request No. 405, Staff/602, Schwartz/68.

Q. WHY DO YOU DISAGREE WITH PGE THAT THE NOTIFICATION REQUIREMENT SHOULD SIMPLY BE TWO CALENDAR YEARS AND DISAGREE WITH PGE'S PROPOSED TWO-YEAR WAITING PERIOD FOR ADDITIONAL REQUESTS?

A. The effect of PGE's proposal is that a customer could be required to wait as much as three years for the first requested change in Baseline Demand to take effect, and as much as five years for a second such request to take effect.

For example, consider a customer with a 40 MW generator that submitted on March 1, 2007, a request to increase Baseline Demand by 10 MW, and then on July 15th of that year experienced a catastrophic failure of the on-site generator. Say the customer advised PGE in July that it wanted to increase Baseline Demand another 30 MW to address the equipment failure.

The customer's first requested change in Baseline Demand would take effect January 1, 2010, nearly three years after the request was made. PGE would not accept until March 1, 2009, the customer's second request to increase Baseline Demand (two years following the last such request). The customer would then wait until January 1, 2012 — two calendar years after PGE's acceptance date — for the second change in Baseline Demand to take effect. That's a 4-1/2 year wait for the second change to take effect from the date the customer made the request. *See* PGE's responses to Staff Data Request Nos. 514-515, Staff/602, Schwartz/61, 63.

Q. HOW WOULD THIS EXAMPLE BE TREATED UNDER STAFF'S PROPOSAL?

A. Under staff's proposal, the customer's initial 10 MW request to increase Baseline Demand would take effect January 1, 2009, 22 months after the request was made. The customer's second request to change Baseline Demand would be accepted by PGE immediately upon receipt, in July 2007, rather than March 2009, two years from the date of the last request, as PGE proposes.

Because the second request was made later than July 1st, the additional 30 MW in Baseline Demand would take effect on January 1, 2010, about 2-1/2 years from the date of the request. Had the second request instead been made before July 1st, the higher Baseline Demand would have gone into effect January 1, 2009.

Q. WHY DOES STAFF SUPPORT A CALENDAR YEAR EFFECTIVE DATE, AND PROPOSE A JUNE 30TH DEADLINE FOR DETERMINING WHICH CALENDAR YEAR THE CHANGE WILL TAKE EFFECT?

A. As in PGE's proposal, staff recommends a January 1st effective date for changes in Baseline Demand due to changes in operation to coincide with the January 1st rate change associated with PGE's annual RVM.

A June 30th cutoff date is appropriate because it provides at least 18 months' advance notice for PGE to economically adjust its net position for the future change in Baseline Demand. An 18-month advance notice period is a reasonable method of minimizing the impact of the change in Baseline

Demand on cost of service customers. If in the future the Commission discontinues the annual RVM, Staff recommends that the change in Baseline Demand take effect 18 months from the date of the requested change, rather than at the start of a calendar year.

Q. PLEASE EXPLAIN THE TYPES OF CIRCUMSTANCES THAT WOULD BE SUBJECT TO PGE'S PROPOSED NOTICE REQUIREMENTS.

A. The notification requirements would apply only to changes in generator capacity and generation operations. Such changes could be due to changing economics of generator operations related to natural gas prices or a long-term failure of the customer's generator. Staff agrees with PGE's statement that "A change in the customer's net load resulting from on-site generation output reduction is not a new load but a shift in generation source initiated by the customer." *See* PGE/1300, Kuns-Cody/38; PGE's responses to Staff Data Request No. 406 and ICNU Data Request No. 1.4, Staff/602, Schwartz/69-71.

PGE also states that a customer must give two calendar years' notice to modify Baseline Demand if the request is the result of installing additional generator capacity. *See* PGE's response to Staff Data Request No. 518, Staff/602, Schwartz/72. The fundamental purpose of establishing Baseline Demand is to determine the level of energy the customer is entitled to at cost of service rates. Because the customer is billed only for energy actually consumed, the customer installing additional generator capacity is not disadvantaged in this respect. However, as I explained previously, Baseline Demand serves as the minimum level for determining the Facility Capacity (distribution) charge. Therefore, the customer would continue paying at least that minimum level until the notification period is expired. Staff finds this reasonable because Facility Capacity charges cover consumer-specific costs for dedicated distribution facilities and shared facilities close to end users, which generally include 13 kV lines and utilization transformers, whose freed-up capacity cannot be counted on to be available to other customers. *See* UE 158 joint testimony, PGE-OPUC Staff, Drennan-Schwartz/6.

Q. PLEASE EXPLAIN THE TYPES OF CIRCUMSTANCES THAT PGE'S PROPOSED NEW NOTICE REQUIREMENTS WOULD *NOT* APPLY TO.

A. The proposed two-year notice requirement would not apply to requests to change Baseline Demand due to decreases in the customer's on-site load, as in the case of a downturn in the customer's business, or to increases in the customer's on-site load – for example, addition of a production line. PGE treats such load changes the same for both full and partial requirements customers. PGE notes that it typically has notice well in advance of new loads. *See* PGE's responses to Staff Data Request Nos. 401-402, Staff/602, Schwartz/73-74.

The two-year notice requirement also does not apply to permanent energy efficiency measures, load shedding, or permanent removal of end-use or generating equipment. *See* PGE's responses to Staff Data Request Nos. 398 and 511, Staff/602, Schwartz/75-76.

Q. PLEASE EXPLAIN THE POSSIBLE INTERACTIONS BETWEEN ENERGY EFFICIENCY MEASURES AND GENERATION OPERATIONS.

A. To clarify the interactions that may occur between energy efficiency measures and generation operations, Staff asked PGE to clarify what would happen in a situation where a customer installed permanent energy efficiency measures that in turn led to a reduction in overall generating capacity – shutting down all or some on-site generating units. In this situation, the customer may wish to reduce generation because the efficiency measures reduced on-site load, the load no longer supports the previous generation level, and the customer is unable to make economic power sales to make up the difference given natural gas and electricity prices. Therefore, the customer may want to *increase* Baseline Demand because the shutdown of one or more of its generating units increases its need for power generated off-site.

PGE states that a customer could request a *decrease* in Baseline Demand without any extended notification requirement because of installation of permanent efficiency measures. However, the customer would be required to wait two calendar years for an *increase* in Baseline Demand to take effect to reflect a change in generation operations. *See* PGE's response to Staff Data Request No. 513, Staff/602, Schwartz/77.

Q. WHAT IF A CUSTOMER PERMANENTLY REMOVES GENERATING UNITS?

A. If a customer permanently removes *part* of its on-site generating equipment, the two-year notice requirement for increasing Baseline Demand would not apply. If *all* generating units are permanently removed, the customer is no longer subject to partial requirements service and would immediately begin receiving service under proposed Schedule 89. *See* Special Condition 8 in Schedule 75, and PGE's response to Staff Data Request No. 513, Staff/602, Schwartz/77.

Q. DO STAFF'S PROPOSED CHANGES TO PGE'S PARTIAL REQUIREMENTS PROPOSAL TAKE CARE OF ALL ISSUES RAISED WITH PGE'S EARLIER FILING (ADVICE NO. 05-17)?

A. No. PGE withdrew Advice No. 05-17, which sought to add notification requirements to Schedules 75 and 575 due to changes in generation. Comments made pursuant to the filing, and by the sole customer on Schedule 75, indicate conflicting interpretations of some of the terms used in the special conditions. These terms remain unclear and could continue to be a source of conflict between PGE and partial requirements customers in the future.

Staff recommends the Commission require the company to modify Schedules 75 and 575 to include definitions consistent with those provided by PGE in response to Staff data requests. Specifically, Staff recommends that the following terms used in Special Condition 8 in Schedule 75 and Special Condition 7 in Schedule 575 be defined in the tariffs: "modified," "permanent energy efficiency measures," "load shedding" and "removal of equipment." *See* PGE Advice No. 05-17; Staff Report on PGE Advice No. 05-17 for the November 8, 2005, public meeting; and PGE's responses to Staff Data Request Nos. 397-399, 400 and 511, Staff/602, Schwartz/75-76, 78-80.

Q. WHAT IS THE ISSUE RAISED BY PGE REGARDING RESTRICTIONS ON A CUSTOMER-GENERATOR'S SALES TO THIRD PARTIES?

A. PGE interprets Schedule 75 in conjunction with Rule F as prohibiting a partial requirements customer from selling some of its power from on-site generation to a third party, unless it has met all of its energy requirements through self-generation and does not take energy from PGE. *See* PGE's response to Staff Data Request No. 407, Staff/602, Schwartz/81-82. Staff finds this in violation of 18 C.F.R. § 292.303(b), which obligates a utility to sell to a Qualifying Facility any energy and capacity requested. Most facilities that would be taking service from PGE under Schedule 75 would be eligible for Qualifying Facility certification by the Federal Energy Regulatory Commission.

Further, PGE is required under 18 C.F.R. § 292.303(a) to purchase all of a Qualifying Facility's output, less an amount equal to the power it needs to generate the output. Utilities also are obligated to wheel power if the Qualifying Facility prefers to sell to a third party. Prohibiting the partial requirements customer from selling to a party other than PGE would be anti-competitive.

Q. ARE YOU CONCERNED THAT A CUSTOMER-GENERATOR COULD GAME THE SYSTEM IF IT SELLS TO A THIRD PARTY AND PGE PROVIDES BACKUP OR SUPPLEMENTAL POWER?

A. No. Appropriate metering as well as notification requirements for changing Baseline Demand due to changes in generation operations would prevent gaming in this respect.

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS ISSUE?

A. I do not believe a tariff change is necessary. Rather, PGE is misinterpreting Schedule 75 as approved by the Commission. Therefore, I recommend the Commission direct PGE to provide any backup and supplemental service to Qualifying Facilities as requested in accordance with federal regulations.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 180/UE 181/UE 184
WITNESS: Lisa Schwartz

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualification Statement

August 9, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	Lisa Schwartz
EMPLOYER:	Oregon Public Utility Commission
TITLE:	Senior Analyst, Resource and Market Analysis Division
ADDRESS:	550 Capitol Street NE #215 Salem, OR 97301-2551
EDUCATION:	Master of Science, Land Resources (1982) University of Wisconsin Madison, Wisconsin Bachelor of Science, Environmental Studies (1980) George Washington University Washington, D.C.
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission since May 2002. My primary responsibilities are to provide expert analysis of issues related to distributed generation, advanced metering, demand response, pricing options, renewable resources, and resource planning and acquisition. From November 1995 to April 2002, I worked for the Oregon Department of Energy as an analyst in the Energy Resources and Conservation divisions. Duties included analysis of energy usage and savings data, state and utility programs, rate design and policy options. From March 1987 through October 1995, I was a researcher and assistant administrator for the Oregon State University (OSU) Extension Energy Program. Earlier work experience includes research and analysis at the OSU College of Engineering, the Wisconsin Water Resources Center, an Oregon economics consulting firm and a Washington, D.C., law firm.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 357

Request:

If PGE plans to hire a third-party installation contractor(s) for meter installation, please state the process PGE will use to solicit bids and the projected dates for an RFP process, including proposal deadlines, expected contract execution date, and expected start and completion dates for meter installation.

Response:

PGE is preparing to issue an RFP to solicit competitive bids for meter installation. We currently plan to release the RFP in mid-June with a proposal submission deadline approximately 4 weeks later. Execution of a contract with the meter installer could occur by September or October 2006.

If approved by the OPUC, there will be two stages of AMI deployment. Stage 1 system acceptance tests (SAT) involve the deployment of approximately 22,000 meters and will begin in late fourth quarter 2006 or early first quarter 2007. After successful completion of the series of SATs scheduled during Stage 1, mass deployment (Stage 2) of approximately 820,000 meters would begin in the third quarter of 2007 and continue for approximately 24 months into 2009.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 349

Request:

Please describe the installation process for the RF meters.

Response:

PGE expects that the RF meters will come pre-programmed and ready to install straight from the factory. An installer will record old and new meter reads and associated identifiers. The exception from the current meter exchange process is that we will use an electronic work order process to minimize transcription errors and lost work orders. The installation (i.e., meter exchange) is otherwise identical to current processes.

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May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 350

Request:

Please describe the installation process for the PLC meters.

Response:

PGE expects that the PLC meters will come pre-programmed and ready to install straight from the factory. An installer will record old and new meter reads and associated identifiers. The exception from the current meter exchange process is that we will use an electronic work order process to minimize transcription errors and lost work orders. The installation (i.e., meter exchange) is otherwise identical to current processes.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 351

Request:

Please describe the installation process for the phone meters.

Response:

Phone-based technology is the planned solution in the rare instances where neither an RF nor PLC technology will be effective. The installation process for phone-based AMI meters would be the same as for RF or PLC meters (see PGE's response to OPUC Data Request Nos. 349 and 350), with the exception that the phone-line connection will be activated by phone company technicians who will make the connection at the time of meter installation.

July 7, 2006

TO: Jason Eisdorfer
CUB

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to CUB Data Request
Dated June 22, 2006
Question No. 004

Request:

For the program that was proposed in UE 115 and adopted by the Commission, please provide the following:

a. **The number of meters that were expected to be required by the customer choice elements (direct access and the portfolio) of SB 1149 for the test year and each year following the test year**

b. **The number of meters that were planned in addition to what was required by the customer choice elements of SB 1149 for the test year and each year following the test year**

c. **The actual number of meters that were installed that were part of the customer choice elements of SB 1149 for the test year and each year following the test year**

d. **The actual number of meters that were installed that were in addition to what was required as part of the customer choice elements of SB 1149 for the test year and each year following the test year.**

Response:

a. PGE forecasted 13,000 meters for large commercial customers and 15,000 meters for residential and small commercial portfolio customers to meet SB1149 requirements. Deployment was forecasted to occur in 2001 and 2002.
b. PGE forecasted the following additional meters:
   - 22,000 meters for the Gresham test area; deployment was forecasted to occur in 2000.

- 10,000 meters to avoid costly meter-reading routes; deployment was forecasted to occur in 2001 and 2002.
- 22,000 meters for various elected services such as preferred due date; deployment was forecasted to occur in 2001 and 2002.

c. Approximately 2,500 meters were purchased for large customers and approximately 8,000 for portfolio customers. Installation occurred in 2001 and 2002. Please note that approximately 6,200 meters for portfolio customers are from the Metering Technology Corp. that will not be included in future rate making according to Commission Order 03-518 (Docket UI-216).

d. Approximately 12,300 meters were purchased for test areas and approximately 3,600 meters for rural routes on Mt Hood. Approximately 9,100 of the test meters were purchased in 2000. The 3,600 rural meters were primarily installed in the second half of 2001. The remaining test meters were installed in 2002, 2003, and 2004.

June 30, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated June 19, 2006
Question No. 507

Request:

For each meter type identified in response to Staff Data Request No. 506 that already provides energy usage data to PGE by time of day, please explain why PGE proposes to replace the meter.

Response:

Excluding the meters listed in PGE's response to OPUC Data Request No. 508, there are approximately 35,000 non-residential solid state meters (all forms) that have time-of-use (TOU) capability but do not have the ability to store interval data. PGE proposes to replace these meters if we cannot retrofit them into AMI meters. The primary reasons are the high cost to manually read these meters and the high cost to program these meters if the time period in a TOU rate changes. In addition, these meters will not support critical peak pricing. We propose to replace the remaining non-residential meters listed in PGE's response to OPUC Data Request No. 506, because they have no TOU capability and replacing them will provide the estimated benefits described in PGE Exhibit 800.

June 30, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated June 19, 2006
Question No. 508

Request:

Please state which nonresidential meters the company does *not* intend to replace through its AMI proposal in PGE/800, by customer size, meter type and number of meters.

Response:

PGE objects to this request on the basis of undue burden. Meter retention is based on the meter's functionality and not on the size of customer served. Further, PGE cannot provide customer size without considerable time and effort. Without waiving this objection, PGE provides the following types and quantities of meters:

Group 1: PGE has 15 meters (9S & 16S) with special functionality. These meters are located on customer sites on our distributed generation program and on customer sites where monitoring power quality is important. These meters have communication capability so that PGE can collect data on a daily basis, or as required.

Group 2: PGE has 100 meters (9S & 16S) with telephone modems and all are equipped to collect interval data. These meters have communication capability so we collect data on a daily basis or as required.

Group 3: PGE has 100 meters (9S & 16S) identical to Group 2 except that there is a recurring telephone charge (approximately $12 to $35 per month per meter) to read these meters, either for PGE or the customer. All these meters will be exchanged because the payback of a new AMI meter (installed cost is approximately $420) to avoid the recurring cost is 1 to 3 years. PGE will retain these meters until we determine if there is a location where these meters can be utilized without a recurring cost.

Group 4:
By year end 2006 (prior to when we would sign definitive AMI vendor agreements for our proposed AMI deployment), PGE will have approximately 3,000 non-residential meters (6S, 9S, & 16S) that are supported by most of the vendors we are considering for the AMI project. In other words, depending on the AMI vendor selected, PGE plans to install internal communication modules, which will allow the meters to provide AMI functionality. We began purchasing these meters in late 2005 as our standard commercial meter. All of these meters will be exchanged, then retrofitted and tested, before using them in our AMI meter inventory.

Group 5: PGE has 2,050 non-residential meters (6S, 9S & 16S) mostly installed in 2001 to support direct access and other market-based pricing options. In general, these meters are installed on PGE's largest customers. These meters each have a monthly recurring cost and the proposed AMI meters have a five-year payback to avoid these costs (i.e., the recurring communication cost per meter is $6.25 per month and the new AMI meter installed cost is approximately $420). In addition, most of these meters have a battery that PGE expects will fail within the next 3 years. The new AMI meters under consideration do not require a battery. Consequently, the actual payback is considerably less if the installed battery replacement cost of $175 is considered. PGE will retain these meters until we determine if they are more useful to serve isolated locations, based on their more powerful radios, than the proposed AMI meters.

Group 6:
PGE has approximately 1,000 (all non-2S forms) solid state meters that store interval data and have the capability to be programmed with time-of-use (TOU) rates. These meters are used for load research locations and also at some large customer locations. All of these meters will be exchanged in order to have a meter with communications capability. If these meters can be converted to AMI meters, we will do so, if cost effective. Otherwise PGE will retain these meters until we determine what locations might require manual interval data collection because no AMI network service is available.

Group 7:
PGE has approximately 2,500 solid state 2S meters (single phase, 240 volt service) that store interval data and have the capability to be programmed with TOU rates. Most of these are used to support customers on residential and small commercial TOU schedules. Some are being used for load research. For the same reason as Group 6, these meters will be exchanged, but PGE will retain them until we determine what locations might require manual interval data collection because no AMI network service is available.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 356

Request:

Please state whether PGE will hire a third-party installation contractor(s) for each type of meter (RF, PLC and phone).

Response:

PGE currently plans to hire a third-party contractor to install the majority of AMI meters. We also plan to use our own resources to install the radio frequency collectors and all primary metered locations.

June 8, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 9, 2006
Question No. 429

Request:

Please describe the advanced metering infrastructure (AMI) technology and cost trends since PGE's last general rate case (UE 115), and the projected trends over the next five years, that lead the Company to believe that 2007-09 is the appropriate time to install an AMI system. Please provide copies of the information the Company relied upon in responding to this data request.

Response:

As noted in PGE Exhibit 800, pages 2 through 4, AMI is a mature technology. PGE would not be a pioneer in the field of AMI; we would be following the lead of a host of other utilities, both large and small, that have seen the value of AMI. In addition, a number of parties have signaled their interest in moving forward with future methods of grid management and demand response.

AMI Cost Trends

Power Line Carrier-based (PLC) AMI: The cost to implement PLC metering has not changed significantly in the last six years, and PGE does not expect a significant change in the future. The cost to interface communications safely on the power grid – at both the meter end-point and at the substation – adds a significant cost per point that cannot be reduced with advances in electronics. However, increased utility acceptance of the lower-cost, two-way radio technologies might cause small price decreases as competition puts pressure on the PLC vendors.

Radio-based AMI: The cost to implement two-way radio-based communications has decreased 10% to 20% as AMI vendors borrow heavily from the substantial engineering knowledge gained to manufacture mobile phones, WiFi, and Bluetooth devices, etc. However, with high fixed costs, long lead time for projects, and considerable risk for vendors in the AMI industry, PGE does not see the basis for significant price decreases over the next 5 years.

AMI Technology Trends
Power Line Carrier-based AMI: Over the last six years, one of the three leading PLC vendors, DCSI, has improved bandwidth and features in the host software. DCSI now faces increased competition from a new two-way solution by Hunt Technologies and increased acceptance of Cannon Technologies' two-way PLC system. Compared to modern communication networks, the bandwidth of PLC systems is very poor and the introduction of new vendors seems unlikely. Broadband over Power Line (BPL) is considered separately below.

Radio-based AMI: PGE received a number of radio-based solutions offered in response to its recent RFP. This is largely due to the advances in radio communications cited above. However, to successfully commercialize an AMI system, a vendor faces significant barriers to entry and PGE will only consider proposals from well-established companies in good financial standing. Although acceptable radio systems are lower-cost and generally have more functionality than the PLC technologies, all the radio technologies have less proven time in the field.

Emerging AMI Technologies: There is considerable discussion about various alternatives using Internet-based metering and interoperable meters. The latter term means any meter that can be used with a wide variety of communication devices placed inside the meter. While this is technically possible, PGE does not believe that it will occur in a robust way within the next five years. Among the significant issues that must be resolved before this can happen include the following:

- The utility industry must develop a system of standard measurement criteria for communication interoperability.
- Internet-Protocol (IP) based standards make security breeches easier. Consequently, a robust security model must be developed to protect information at the meter end-point.
- A highly fragmented utility industry has only modest influence on products developed by AMI vendors. Therefore, once standards are developed, a means to motivate AMI vendors to adopt the standards must be achieved.
- A viable IP-based system requires nearly ubiquitous premise access to an "always-on" internet network. Rural and lower-income residential areas do meet this requirement.

Other Potential Supporting Technologies:

- Broadband over Power Line (BPL) is a communication option (not directly related to AMI functionality) that is a wide-area-network communication technology to support Internet Protocol. As such, it will compete directly with DSL and Cable broadband services. Currently, the cost to implement a BPL network solution support of AMI would add substantially higher investment and recurring costs. Ultimately, BPL is commercially unproven and without a single, large-scale implementation in the U.S., BPL represents an unwarranted risk to support AMI.

Appropriate Time to Install an AMI System
See PGE Exhibit 800, page 3, line 17 through page 4, line 2, and "AMI Cost Trends," above.

Basis of this Response
The information above is based entirely on PGE's general knowledge of AMI vendor technology as well as manufacturing trends observed in the market. Personnel within PGE have been monitoring and working with this industry since 1993. PGE has no specific documents to provide with this response.

June 8, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 9, 2006
Question No. 438

Request:

Please explain PGE's plans regarding future employment at the Company of meter readers that would no longer be needed if the Company installs AMI.

Response:

PGE does not plan to provide employment guarantees for meter readers that will no longer be required if PGE installs the proposed AMI system. Instead, PGE has conducted a career day and counseling for meter readers to make them aware of potential opportunities elsewhere within the company. Meter readers may always apply for, and are considered for, open positions within PGE for which they are properly qualified. Because of this, PGE has experienced approximately 35% and 48% turnover rates for meter readers in the last two years.

Open meter reader positions in the near term will be hired on a temporary basis to meet PGE's interim needs. PGE will notify those hired that there is a definite end point to their employment as meter readers and that there is no guarantee of other opportunities within PGE. This approach will potentially reduce the need for severance payouts. These payouts are included in PGE's response to OPUC Data Request No. 374, Attachment 374-A, "O&M Summary" tab, row 93.

UE 180
Attachment 374-I

Provided electronically (CD)

Updated Table 1 from Exhibit 800

AMI Capital Costs ($ millions)	**2006**	**2007**	**2008**	**2009**	**Totals**
RF Meters Including Installation	856.9	17,797.1	48,018.9	23,856.2	90,529.1
PLC & Phone Meters Including Installation	796.4	4,980.0	14,580.9	6,124.8	26,482.2
Meter Testing and Field Supervision	354.9	1,533.3	2,123.5	967.8	4,979.5
Systems Development	2,317.9	3,332.5	2,752.9	483.0	8,886.3
Servers & Storage	266.6	837.9	1,719.6	504.4	3,328.6
Network Equipment	146.3	1,346.8	3,471.0	1,000.4	5,964.5
Licenses, Handhelds & Misc.	140.7	284.8	240.0	175.0	840.5
Totals	4,879.8	30,112.4	72,906.8	33,111.6	141,010.6

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 385

Request:

Please refer to PGE/800, Hawke-Carpenter/Tooman/11, Lines 18-21. Please explain how PGE would use the Oregon Business Energy Tax Credit (BETC) to offset AMI costs and how use of the tax credit would reduce AMI costs to ratepayers. Provide electronic spreadsheets and workpapers with all cells and formulae intact showing potential tax credit benefits. State all assumptions used in the analysis.

Response:

Oregon BETC is a tax credit that may be used to offset Oregon income tax liability per ORS 315.354. A total of 35% of the certified cost of a project may be claimed as a tax credit over a five-year period (10% in the first and second years, and 5% in the following three years). A BETC certification will not be issued for more than $10 million (OAR 330-090-01500). BETC credits that cannot be utilized on the current year's tax return may be carried over to offset future Oregon income tax liability for up to eight years. PGE anticipates that any tax savings generated from utilization of BETC derived from AMI would be deferred for future refund to customers. Major assumptions concerning BETC for AMI include receiving project cost certification from the Oregon Department of Energy and that PGE will generate adequate Oregon tax liabilities in future years to utilize these tax credits. PGE may also need to reassess the appropriate treatment of BETCs pending final resolution of AR 499, the rulemaking docket related to SB 408.

PGE has created no specific spreadsheets or work papers to show potential tax credit benefits for the proposed AMI project.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 386

Request:

Has PGE applied for precertification from the Oregon Department of Energy (ODOE) for a BETC for its AMI proposal? Please provide a complete copy of PGE's application and ODOE's response.

Response:

PGE has not applied with Oregon DOE for BETC on the AMI project. PGE is initiating contact with ODOE to begin that process.

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May 17, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 382

Request:

Please refer to PGE/800, Hawke-Carpenter/Tooman/6, Lines 1-4, and Hawke-Carpenter/Tooman/11, Lines 11-12, 14. Please state all assumptions related to projected costs and savings of automated disconnect/reconnect technology that is included in PGE's analysis of AMI system costs and benefits. Include PGE's proposed strategy for where such technology will be used, including customer type and characteristics and number of residences and businesses, and how installation of such technology will be coordinated with installation of AMI.

Response:

Background:

The automated disconnect/reconnect capability is created by:
a) A meter with a service disconnect relay (SDR) installed inside the meter housing (the integral design). This is the low-cost option for RF meters.
b) A meter socket extension collar with an SDR. The collar is installed in the customer's meter socket and then the meter is installed in the collars socket. At the time PGE was preparing its AMI proposal, this was the only option available for PLC meters.

At the time of the meter installation, a control wire for the relay in the collar is connected to the back of the meter. With both SDR options the communication link to the AMI meter is used to send control signals to open or close the relay from PGE's communication center. Positive confirmation of the relay position is possible because of the two-way capability of the AMI system. The relay operates only on the customer's side of the meter so when the electric service is disconnected the meter and the communication device remain energized and functional.

Strategy

PGE's proposed implementation for automated disconnect/reconnect capability during the AMI deployment is to install an SDR at all rental (i.e., non-owner occupied) residences. We originally estimated that 235,000 such installations will be made: 190,000 using the integral design option and the remaining premises will use the collar-based option. The option mix could vary; however, as more meter manufacturers are offering an integral design option. During installation, the work order for every meter will specify the specific meter model and SDR option, if any, to be installed. There is no incremental cost to install the service disconnect relay with the integral design. With the collar option, the install process takes approximately 30 seconds longer.

Cost assumptions

The major assumptions for the automated disconnect/reconnect program are as follows:

- The incremental cost for a meter with an integral design – row 62 less row 63 from "Capital Assumptions" tab in Attachment 374-A.
- The cost for a collar-based option – row 64 less row 65 from "Capital Assumptions" tab in Attachment 374-A.
- With the above incremental costs, the AMI projection includes approximately $20 million for the integral service disconnects and approximately $6.3 million for the collar-based disconnects.
- The development cost to design the process and implement the automated disconnect/reconnect system is estimated to be approximately $2.0 million.

Savings assumptions

Based on analysis of PGE's service disconnect records, we found that approximately 60% to 70% of the service disconnect operations performed each year occur at residential, non-owner occupied premises. We believe this proportion justifies the blanket deployment of SDRs as described above. Accordingly, we estimated a cost reduction of approximately two-thirds of the full time employees performing disconnections. Reduced labor costs, however, represents only one of the areas where cost savings occur. Currently, in order to justify the expense of a site visit, PGE might defer disconnects for some time. With an SDR present, there is a very small marginal cost to conduct the disconnect operation. Consequently, PGE will be able to perform a disconnection earlier according to the schedule permitted by OPUC rules.

Based on 2004 data, the automated disconnect/reconnect program will allow approximately 54 days earlier disconnection on accounts that will have SDRs and approximately 26 days earlier disconnection on accounts that will not have SDRs. In addition, after a service disconnection is performed, approximately 82% of the past due amounts are collected, mostly with a few days.

Based on these assumptions (and an average 30 kWh per day usage and eight cents per kWh), the automated disconnect/reconnect program will result in approximately $6.5 million to be collected on average an estimated 50 days earlier. This collection causes a one-time reduction in working capital and associated annual reduction in the revenue requirement for that working capital. Reductions in working capital are listed in PGE's response to OPUC Data Request No. 374, Attachment 374-B, "O&M-Working Cash" tab. In cases where past-due amounts are not collected, we estimate that the earlier disconnects will generate an annual power cost reduction of approximately $1.2 million for energy no longer delivered.

An additional benefit of using an SDR process relates to the move-in/out process. In approximately 20% of non-owner occupied residences, the landlord has not agreed to automatically pay for energy when a resident moves out. In these cases, during the period starting when the current occupant moves out until the next occupant moves in, no one is responsible for energy consumption. This occurs at approximately 20,000 rental properties per year, and assuming 100 kWh is unbilled per transition, PGE experiences a loss of approximately 2 million kWh per year. With an automated disconnection after a move-out, the SDR prevents energy from being used and power costs could be reduced by approximately $100,000.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 363

Request:

Please provide PGE's implementation plan for the following items, including but not limited to timeline, costs and savings.

a. Demand benefits (demand response programs and direct load control)
b. Outage reporting
c. Outage detection
d. Restoration
e. Better distribution planning
f. Economic benefits (cost savings)
g. Functional benefits for customers and employees (convenience, safety)

Response:

a. PGE is currently planning to include demand-side resources in its 2006 Integrated Resource Planning process, including direct load-control programs. The outcome of the resource planning process will inform any subsequent implementation plan.
b. PGE has not developed a timeline or estimated the costs and savings associated with outage reporting. Cost/benefit analyses might take place as early as 2008, but system automation, if cost effective, would not likely occur before 2010. For more information on outage reporting, see PGE's response to OPUC Data Request Nos. 364 and 367.
c. PGE has not developed a timeline or estimated the costs and savings associated with outage detection. Cost/benefit analyses might take place as early as 2008, but system automation, if cost effective, would not likely occur before 2010. For more information on outage detection, see PGE's response to OPUC Data Request Nos. 364 and 367.

d. PGE has not developed a timeline or estimated the costs and savings associated with restoration. Cost/benefit analyses might take place as early as 2008, but system automation, if cost effective, would not likely occur before 2010. For more information on restoration, see PGE's response to OPUC Data Request Nos. 364 and 367.
e. PGE has not developed a timeline or estimated the costs and savings associated with better distribution planning. However when the AMI system is deployed and resources are available, PGE plans to evaluate the following concepts for improved capital utilization based on additional information provided by the AMI system:
   - By aggregating meter data served by specific substations, PGE could identify alternative configurations of feeder lines with adjacent substations so as to potentially defer upgrades on substations approaching service limits.
   - By aggregating meter data served by a specific transformer, PGE could identify under- or over-utilized transformers and replace them with ones having the correct capacity.
f. For detailed information on cost savings, see PGE's response to OPUC Data Request No. 374, Attachments 374-A, 374-B, 374-E, and 374-F.
g. With the exception of "customer selected due date" (CSDD), PGE has not developed a timeline or estimated the costs and savings associated with functional benefits for customers and employees. For CSDD, PGE included the following estimates in its analysis of the proposed AMI system:
   - Costs – approximately $1.5 million in IT costs to develop the CSDD program.
   - Benefits – approximately $5 million annual reduction in Working Cash rate base (see PGE's response to OPUC Data Request No. 374, Attachment B, "O&M-Working Cash" tab.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 364

Request:

Please explain how PGE's AMI proposal would improve outage reporting, detection and restoration.

Response:

Outage Reporting:
The proposed AMI system will enable PGE to collect blink counts and specific outage start/stop times for longer outages by meter. Outage reporting accuracy will improve with the additional detail, which will also increase the accuracy of PGE's reliability reporting (SAIDI, SAIFI, MAIFI, etc.).

Outage Detection:
PGE Exhibit 800, page 11, noted that AMI systems have the potential for improved outage detection. PGE's proposed system (based on the budgetary quotes) did not include this particular feature. When the current RFP process is complete, however, the final system could include the capability for timely outage detection. If so, the AMI system will supplement this portion of the outage detection process and also detect outages when customers are less likely to respond, such as when they are at work or asleep.

Restoration:
Some AMI systems provide the ability to "Ping" meters in a localized area to verify all meters on a tap line have power when the tap line is restored. Depending on the level of outage information by meter, PGE's field crews could be able to completely restore service in an area before being dispatched to another location.

May 17, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 365

Request:

Please explain how PGE's AMI proposal would allow for better distribution planning.

Response:

Accurate, geographic-specific usage data enables PGE personnel to effectively plan and manage PGE's distribution system. These data can be assembled at the individual customer level up to feeder level and will allow PGE to evaluate transformer, feeder, tap, and fuse loading in a much more detailed manner than previously possible. PGE could use this load information to improve system reliability and to identify potential overloading prior to equipment failure. This information can also help to identify equipment that is oversized for its actual load, which would lead to potential cost savings in selection and use of equipment that is more appropriately sized for the loads.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 366

Request:

Please explain how PGE's AMI proposal would allow for improved detection of energy losses.

Response:

PGE is planning to initially implement three methods to reduce energy losses.

- The process of exchanging 100% of meters creates a one-time opportunity to examine all meter sockets and identify suspect wiring. With the status quo, decades could elapse between meter exchanges.
- The use of 100% solid state meters means that they cannot be affected the way mechanical meters can (e.g., turned upside down or slowed down) to reduce billable revenues.
- The proposed AMI system will allow more extensive high/low reading checks than PGE can perform with manual monthly reads. These checks will identify failed meters more quickly, as well as some type of energy diversion.

In addition, the availability of interval data should prove useful in the investigation of suspected energy diversion.

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May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 367

Request:

Please explain how improved outage reporting, detection and restoration reduce utility costs.

Response:

Outage Reporting
Outage reporting is used to gauge the effectiveness of restoration efforts. With more accurate information available, service can be continually improved. For example, more accurate outage reports could lead to refined targeting for maintenance work, thus improving the cost effectiveness of maintenance and improved outage statistics.

Outage Detection
Outage detection cost reductions are derived primarily from limiting the number of field crews assigned due to a lack of information. When the system automatically identifies the device that has failed, PGE can assign the correct worker or crew to that job. This could also reduce the length of the average outage.

Restoration
The "pinging" described in PGE's response to OPUC Data Request No. 364 increases the effectiveness of work crews. If a localized set of meters do not have power after the tap line is restored, then PGE's crew can address the issue before leaving the area. This will reduce the number of return trips and decrease the length of the average outage.

May 17, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 368

Request:

Please explain how better distribution planning reduces utility costs.

Response:

As noted in PGE's responses to OPUC Data Request Nos. 363 and 365, PGE could use the load information provided by the AMI system to improve system reliability and to identify potential overloading prior to equipment failure. Such action would reduce outage costs and equipment replacement costs. This same information may also help identify situations where equipment is oversized for its load, which could lead to potential cost savings and improved asset utilization.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 369

Request:

Please explain how improved detection of energy losses reduces utility costs.

Response:

Cost reduction is derived from the direct elimination of power costs associated with energy diversion and/or distribution equipment with excessive losses. In cases of energy diversion where a customer begins payment for energy use that was once unbilled, then energy rates will be reduced for all other customers who otherwise pay for energy diversion through line losses.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 360

Request:

Please refer to PGE/800, Hawke-Carpenter-Tooman/10, Lines 1-17. Please explain how PGE's AMI proposal, as specified in PGE/800, will provide demand benefits given that the company proposes no demand response programs, including direct load control programs, in its rate case filing.

Response:

The testimony on page 10 is a general discussion of the benefits an "AMI system can offer." PGE's proposed system will not be able to offer all of these benefits but may be in a position to do so in the future, depending on the development of demand response programs (such as smart appliances, nationwide) and approval of associated costs by the OPUC. Ultimately, no benefits for demand response were included in Table 2 of the testimony, which represents O&M savings from the AMI system.

PGE's proposed AMI system will support the two main categories of demand response (DR) programs as follows:

- The AMI system will collect meter data needed to support most tariff designs based on time-varying rates.
- The AMI fixed network has 2-way communications paths to read and collect meter data, which can also be used to communicate with load-control devices. The purchase and installation of these devices, however, is not included in the current scope of the AMI project. Further, not all AMI vendors have commercially available load control hardware, but all will support the development required for a specific program, if development costs are provided.

For both types of DR programs, the costs to design and implement system changes have not been estimated or included in PGE's proposed system.

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May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 361

Request:

Please explain how AMI installation will make demand response programs, including direct load control programs, more cost-effective, compared to the company's current metering system. Include in PGE's response the percent of costs that AMI accounts for in residential and commercial time-varying pricing programs, in direct load control programs for water heating, space heating and air-conditioning, and in smart appliance programs.

Response:

PGE's proposed AMI system does not include any costs (including hardware or development costs) or benefits associated with direct load control. The proposed system, however, is more cost-effective than the current metering system with regard to time-varying rates because:

1. The proposed AMI meters (without remote disconnect) cost less than:
   a. Status quo residential meters that support time-of-use (TOU) or critical-peak pricing (CPP).
   b. Status quo commercial meters that support time-varying rates or direct access.
2. The proposed AMI system will eliminate:
   a. Manual costs associated with reading the meters listed in 1.a. above.
   b. Monthly charges for the SmartSynch system to read the meters listed in 1.b. above.
   c. Reprogramming each status quo meter if TOU period definitions change.
3. The AMI system will support TOU and CPP options for all meters in PGE's service territory rather than the small percentage of customers that currently utilize these functions or would use them absent the AMI system.

May 23, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 9, 2006
Question No. 437

Request:

Please specify the assumed depreciation life (in years) for each type of meter (RF, PLC and Phone) included in PGE's AMI proposal.

Response:

PGE assumed 18-year lives for all three meter types. See PGE's response to OPUC Data Request No. 374, Attachment 374-B, "Meters" tab, column C, rows 80 through 109 for the 18-year, remaining-life depreciation rates applied to AMI meters.

June 8, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 15, 2006
Question No. 464

Request:

What depreciation rate, projection life, and Iowa curve is PGE proposing to use for the new meters that would be installed under its AMI proposal, and how did the Company select them?

Response:

Depreciation rates are provided in rows 80 through 109 of the "Meters" tab in Attachments 374-B, 374-C, 374-F, and 374-G (see PGE's response to OPUC Data Request No. 374). PGE used an R-3 Iowa curve with 18-year meter lives, which we selected based on the following considerations:

- An AMI meter has the same meter platform as a 3-phase solid state meter, with an added communication module.
- The design life of a solid state induction meter is 15 to 20 years, which is lower than the expected life of the single phase mechanical meter (25 years).
- The expected life of solid state meters is lower than traditional mechanical meters because solid state meters are more susceptible to the elements.
- The meter display is liquid crystal, and is vulnerable to exposure to sunlight and temperature variation.
- PGE's meter shop statistics for solid state meters support the design life with a high modal survivor curve.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 378

Request:

Please explain why PGE proposes accelerated depreciation of the existing metering capital and the effect on PGE's proposed AMI project of any Commission decision in UE 180 to deny such treatment.

Response:

PGE proposes to accelerate the depreciation of existing metering capital so that the net book value of those meters is zero by the time the proposed AMI system is fully deployed. According to the Oregon Court of Appeals decision in CUB v. OPUC, 154 Or. App. 702, 962 P.2d 744, the Commission cannot set rates that include a return on assets retired with an undepreciated balance.

If the Commission were to deny this treatment, PGE would not pursue an AMI system at this time.

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June 8, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 15, 2006
Question No. 461

Request:

Please explain PGE's proposed schedule for retiring existing metering capital from its books under the Company's proposed accelerated write-off. For example, is PGE planning to retire existing metering capital from the books as it is removed from customer sites?

Response:

Meters are an asset type that is removed in groups rather than item by item. PGE will retire meters from rate base as reported by the field. In the month following replacement, PGE will then accelerate depreciation on those meters so that their net book value is reduced to zero.

June 8, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 15, 2006
Question No. 463

Request:

Please state PGE's salvage assumptions for the existing meters that would be retired under the AMI proposal and the basis for those assumptions.

Response:

PGE has determined that there is little or no market value for retired mechanical meters and, at best, we expect to sell them for a few cents per meter as scrap metal. For replaced solid state meters, PGE expects to sell them for a total of approximately $20,000. However, this amount could decline as increasing quantities of used solid state meters enter the market. Because these amounts are minimal, no salvage assumptions were incorporated in PGE's AMI analysis.

May 23, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 9, 2006
Question No. 430

Request:

Please refer to PGE/800, Hawke-Carpenter-Tooman/7, Lines 14-17. Is the $3.7 million PGE proposes in accelerated depreciation for existing metering capital for the test year (2007) a *one-time expense* for the three-year AMI installation period, or a *recurring expense for each year* during the installation period?

Response:

Please reference PGE's response to OPUC Data Request No. 374, Attachment 374-C ("Compare" tab, row 14) for the annual revenue requirement impact associated with PGE's proposed AMI deferral. The $3.7 million represents the recurring, incremental revenue requirement for each year during the installation period.

June 8, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 15, 2006
Question No. 462

Request:

Please refer to PGE Attachments 374-B and 374-F, "Old Meters" tab, Row 75. Please explain why the proposed "Retirement Rates" of the "Old Meters" are different under the Company's two scenarios: without the additional 21 meter readers vs. with the additional 21 meter readers.

Response:

The retirement rates were adjusted for each case to allow a consistent rate impact over the three-year deployment period. Because the overall AMI revenue requirement impact varies with the addition of the 21 meter readers, the retirement rates are slightly different to achieve the consistent rate impact.

June 19, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated June 9, 2006
Question No. 500

Request:

Please describe how PGE plans to allocate to each rate class and tariff schedule the $3.7 million in accelerated depreciation costs in the test year for existing metering capital as specified in PGE/800. Please provide all documentation, including workpapers, related to the calculation of the allocations.

Response:

The $3.7 million would be an addition to the 2007 test period distribution revenue requirement and would be allocated on an equal percent of marginal cost basis in the same manner depicted in Exhibit 1305, pages 18-22. To estimate the amount that would be allocated to each rate schedule, simply determine the percent of total distribution costs allocated to the schedule and apply that to the $3.7 million. For example, the percentage of total distribution revenue requirement allocated to Schedule 7 is approximately 56.10%.

July 7, 2006

TO: Jason Eisdorfer
CUB

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to CUB Data Request
Dated June 22, 2006
Question No. 008

Request:

Please provide all studies, analysis, and other written material that PGE relied upon when it made the decision to abandon the UE 115 NMR/AMR program and instead launch a different AMR program.

Response:

As described in PGE's response to CUB Data Request No. 003, part b, PGE did not fully implement the NMR system envisioned in UE 115. Instead, our primary NMR vendor suffered business failure and we installed a second-choice system to meet the requirements of SB1149. This system is more costly and less functional than the systems available today. After evaluating the NMR industry for over five years, we prepared a cost-effective solution to PGE's Board of Directors in August 2005. For this analysis, see PGE's responses to OPUC Data Request No 374 (provided in response to CUB Data Request No. 009). For a more detailed discussion of why PGE will replace specific meters, see PGE's responses to OPUC Data Request Nos. 506-509 (provided as Attachment 008-A).

May 23, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 9, 2006
Question No. 432

Request:

Please explain why PGE proposes to establish a deferral account for AMI capital investments for the three-year installation period, instead of filing a rate case for the AMI investment upon completion of the project. For purposes of this data request, assume the Commission approves in UE 180 the Company's proposed AMI investment and accelerated depreciation of the existing metering capital as stated in PGE/800.

Response:

PGE has proposed the deferral mechanism to mitigate the rate increase associated with AMI during the early years of system deployment. This effect can be seen in PGE's response to OPUC Data Request No. 374, Attachments 374-B (without 21 incremental meter readers) and 374-F (with 21 incremental meter readers). A comparison of rows 17 and 29 reveals the difference in annual revenue requirement impacts between implementing and not implementing a deferral for the AMI system.

The primary bases for the annual revenue requirement effects are that: 1) accelerated depreciation of the existing system must be accomplished by the time the AMI system is fully deployed, and 2) the AMI system becomes "used and useful" as it is being deployed. Because these effects are realized in 2007 through 2009, a deferral will reduce the rate impact during those years.

Revenue Requirement Analysis
AMI Full Deployment (R-3 Iowa Curve with 18 Yr Meter Life) and Accelerated Depreciation of Existing Meters
($000)

Line No.			2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
		Base Case - Accelerated Depr for 3-Year Uniform Rate Impact											
1		RevReq - Status Quo Existing Investment, No O&M	7,789	7,748	7,591	7,462	7,399	7,298	7,180	7,181	7,260	7,323	7,416
2		RevReq - AMI Investment less O&M Savings	2,156	7,638	11,857	9,847	8,091	5,916	4,079	2,269	526	(1,010)	(2,421)
3		RevReq - Old Meters plus Accelerated Depr	16,184	10,660	6,284	0	0	0	0	0	0	0	0
4	2 + 3	RevReq - AMI Subtotal	18,341	18,298	18,141	9,847	8,091	5,916	4,079	2,269	526	(1,010)	(2,421)
5	4 - 1	RevReq Delta - Rate Impact	10,552	10,550	10,550	2,384	692	(1,381)	(3,102)	(4,912)	(6,734)	(8,333)	(9,837)
		NPV	(6,248)										
		Defer AMI RevReq for 3 Years - Accelerated Depr for 3-Year Uniform Rate Impact											
6		RevReq - Status Quo Existing Investment, No O&M	7,789	7,748	7,591	7,462	7,399	7,298	7,180	7,181	7,260	7,323	7,416
7		RevReq - AMI Investment plus O&M Savings	-	-	-	19,243	17,488	15,313	4,079	2,269	526	(1,010)	(2,421)
8		RevReq - Old Meters less Accelerated Depr	11,522	11,481	11,322	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
9	7 + 8	RevReq - AMI Subtotal	11,522	11,481	11,322	19,243	17,488	15,313	4,079	2,269	526	(1,010)	(2,421)
10	9 - 6	RevReq Delta - Rate Impact	3,734	3,733	3,731	11,781	10,089	8,015	(3,102)	(4,912)	(6,734)	(8,333)	(9,837)
		NPV	(4,434)										

Revenue Requirement Analysis
AMI Full Deployment (R-3 Iowa Curve with 18 Yr Meter Li
($000)

Line No.			2018	2019	2020	2021	2022	2023	2024	2025	2026
		Base Case - Accelerated Depr for 3-Year Uniform Rate Impact									
1		RevReq - Status Quo Existing Investment, No O&M	7,509	7,561	7,586	7,659	7,767	7,842	7,966	8,180	8,433
2		RevReq - AMI Investment less O&M Savings	(4,313)	(5,427)	(6,263)	(7,787)	(9,248)	(10,638)	(2,529)	6,728	73,085
3		RevReq - Old Meters plus Accelerated Depr	0	0	0	0	0	0	0	0	0
4	2 + 3	RevReq - AMI Subtotal	(4,313)	(5,427)	(6,263)	(7,787)	(9,248)	(10,638)	(2,529)	6,728	73,085
5	4 - 1	RevReq Delta - Rate Impact	(11,822)	(12,988)	(13,848)	(15,446)	(17,015)	(18,480)	(10,494)	(1,452)	64,652
		NPV									
		Defer AMI RevReq for 3 Years - Accelerated Depr for 3-Year Uniform Rate Impact									
6		RevReq - Status Quo Existing Investment, No O&M	7,509	7,561	7,586	7,659	7,767	7,842	7,966	8,180	8,433
7		RevReq - AMI Investment plus O&M Savings	(4,313)	(5,427)	(6,263)	(7,787)	(9,248)	(10,638)	(2,529)	6,728	73,085
8		RevReq - Old Meters less Accelerated Depr	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
9	7 + 8	RevReq - AMI Subtotal	(4,313)	(5,427)	(6,263)	(7,787)	(9,248)	(10,638)	(2,529)	6,728	73,085
10	9 - 6	RevReq Delta - Rate Impact	(11,822)	(12,988)	(13,848)	(15,446)	(17,015)	(18,480)	(10,494)	(1,452)	64,652
		NPV									

May 25, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 9, 2006
Question No. 434

Request:

Please explain how PGE proposes to track these deferral account components during the Company's proposed three-year deferral period.

Response:

PGE proposes to track the AMI deferral account components as follows:

- For purposes of the deferral, PGE will assume that estimated O&M savings will be achieved during the three-year deferral/deployment period.
- PGE will true-up capital expenditures similar to the process used in Staff's UE 115 adjustment, S-45, related to certain PGE capital expenditures incurred from 2000 through 2002/2003.

May 23, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 9, 2006
Question No. 436

Request:

What month and year does PGE plan to file for collection of the deferred AMI capital expenditures?

Response:

In PGE's response to OPUC Data Request No. 374, Attachments 374-C and 374-G, "Deferral" tab, we assumed recovery of the deferral would begin in January 2010. Subsequent to OPUC approval of an AMI deferral mechanism, PGE will target a specific month in which to submit the amortization filing.

Rates and Regulatory Affairs
Facsimile: 503.721.2532

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RECEIVED
JUN - 2 2006
PUC
Utility Program

June 1, 2006

Public Utility Commission of Oregon
550 Capitol Street, N.E., Suite 215
P.O. Box 2148
Salem, Oregon 97308-2148

Attn: Vikie Bailey-Goggins
Administrator, Regulatory Operations Division

RE: Docket UE 180; Staff Request No. 1-5

NW Natural submits the following response to Staff's request for information in the above-referenced matter.

1. Please estimate the additional costs NW Natural would expect to incur within its joint meter reading area with Portland General Electric (PGE) if PGE installs advanced metering infrastructure (AMI) as outlined in Docket UE 180 (PGE/800). Please include the assumptions NW Natural makes in determining these estimates, as well as supporting workpapers showing the cost components with formulae and cells intact.

   NW Natural Response: The incremental capital expenditure required to provide meter reading within the joint meter reading area is estimated to be $4,594,818. The incremental O&M would ramp up to an estimated annual total of $1,565,000 in 2009. The attached file "NWN JMR 0530.xls" provides the assumptions and calculations for these estimates.

2. Please describe the action(s) NW Natural would take in the short run as well as in the long run to address gas meter reading within the joint meter reading area if PGE installs its proposed AMI system. For example, would NW Natural expect to install an advanced metering (drive-by/walk-by) system in the joint meter reading area within the next five years, 10 years or 20 years if PGE installs its proposed AMI system?

   NW Natural Response: NW Natural would conduct a financial analysis to determine whether a traditional or automatic meter reading solution is the most cost effective solution to serve the joint meter reading area. Should it be shown that automatic meter reading is the best solution, it is expected that this would be installed within the next five years.

3. Please describe the action(s) NW Natural would take in the short run as well as in the long run to address gas meter reading within the joint meter reading area if PGE does *not* install its proposed AMI system. For example, would NW Natural continue joint meter reading as it is practiced today so long as PGE does not install an AMI system? Or would NW Natural consider installing an advanced metering (drive-by/walk-by) system in the joint meter reading area within the next five years, 10 years or 20 years, even if PGE did not install AMI?

   NW Natural Response: Should PGE decide not to install its proposed AMI system, in the short run NW Natural would continue with joint meter reading. NW Natural would conduct a financial analysis to determine whether a traditional or automatic meter reading solution best serves the joint meter reading area for the long term.

4. Has NW Natural determined whether there is a positive business case for installing an advanced metering system to read gas meters in the joint meter reading area? For example, has the Company performed a Total Resource Cost analysis to determine ratepayer benefits (reduced revenue requirements)? If the Company has performed such an analysis, please provide the assumptions used in the analysis and workpapers with cells and formulae intact.

   NW Natural Response: NW Natural has not performed a revenue requirement analysis for an automatic metering system to read gas meters in the joint meter reading area. A preliminary analysis indicated that installation of a gas AMR system in the joint meter reading area would not be economic as long as the joint meter reading program continued in that area.

5. Please provide an update on the Company's installation of an advanced metering system outside of the joint meter reading area, including:

   NW Natural Response:

   a. Project start date
      May 2006

   b. Estimated project completion date
      April 2007

   c. Number of meters already converted/replaced
      None

   d. Number of remaining meters to convert/replace
      232,676

   e. Estimated total project costs
      $15,300,000

f. Estimated annual savings
   Estimated annual savings ramp up to a level of $2,275,000 (real dollars) in 2008 exclusive of growth.

g. Net present value (in dollars) of investment
   $1,144,484

Please call if you have questions.

Sincerely,

NW NATURAL

C. Alex Miller

C. Alex Miller, Director
Regulatory Affairs & Forecasting

cc: Stephanie Andrus

JMR Manual Meter Reading
Estimated Capital Cost Summary (real $)

Inflation	**3%**
AFUDC	**7%**
Office Overhead	**56.0%**
OPR Overhead	**53.7%**

CAPITAL SUMMARY	Estimate
Hardware Purchases	$531,101
Software Purchases	$95,000
Misc.	$0
Discounts	$0
I.S. Labor	$938,000
Escalation of IS Labor to 2006 $	$57,124
OPR Labor	$1,316,000
Escalation of OPR Labor to 2006 $	$80,144
I.S. Labor Overhead	$570,161
OPR Labor Overhead	$706,692
Subtotal	**$4,294,222**
AFUDC	$300,596
TOTAL CAPITAL	**$4,594,818**

JMR Manual Meter Reading
Estimated Capital Equipment Purchases (real $)

Item	Vendor	Quant.	Cost Each	Total	Comments
Hardware					
G5R Meter Reading Handheld with [illegible]	Itron	20	$4,490	$89,800	
G5R Battery (Spare)	Itron	5	$85	$425	
G5R Cradle	Itron	20	$495	$9,900	
G5R Power Supply	Itron	7	$103	$721	One per three G5Rs
G5R Modem Serial Cable (6 ft)	Itron	3	$85	$255	One per nine G5Rs
Trucks	Garage	20	$20,000	$400,000	
Routing Workstations	Dell	6	$4,000	$24,000	
Printer	HP	1	$1,500	$1,500	
Plotter	HP	1	$4,000	$4,000	
Freight		1	$500	$500	
Hardware Total				***$531,101***	
Software					
ARCs Licenses with Mapping	[illegible]	6	$1,500	$9,000	
Itron Upgrade	Itron	1	$50,000	$50,000	
Rent		24	$1,500	$36,000	
Software Total				***$95,000***	
Discounts					
				$0	
				$0	
Discounts Total				***$0***	
TOTAL				***$626,101***	

JMR Manual Meter Reading
Estimated Capitalized IS Labor (real $)

	Architect	Capital Projects	Application Services					IS Support Services						Meter Reading	
	Architect	Project Manager	Project Admin	Itron/ARCs Analyst	Analyst	Analyst	Tester	Purchase Support	Network	UNIX System Admin	NT Admin	Desktop Support	DBA	Routing Supervisor	Phase Total
Rate per Hour w/o OH	$100	$100			$75						$75			$75	
PLANNING PHASE															
Project Management		320		40										360	
Servers								80		80					
Network									40						
Database												40	80		
Interface Coding															
Application															
Testing															
Phase Sub-Total in Hours	0	320	0	40	0	0	0	80	40	80	0	40	80	360	*1040*
Phase Cost Sub-Total	$0	$32,000	$0	$3,000	$0	$0	$0	$6,000	$3,000	$6,000	$0	$3,000	$6,000	$27,000	*$86,000*
DESIGN PHASE															
Project Management		320		160											
Servers										40	40				
Network									160						
Database												40			
Interface Design															
Configure Application															
Application															
Testing															
Phase Sub-Total in Hours	0	320	0	160	0	0	0	0	160	40	40	40	0	0	*760*
Phase Cost Sub-Total	$0	$32,000	$0	$12,000	$0	$0	$0	$0	$12,000	$3,000	$3,000	$3,000	$0	$0	*$65,000*
EXECUTION PHASE															
Project Management		3,520		1,440											
Servers								80		80	80				
Desktop												80			
Database													80		
Routing														3,800	
Application															
Testing															
Network Installation									160						
Interface Testing															
Network Installation															
Configure Application															
Phase Sub-Total in Hours	0	3,520	0	1,440	0	0	0	80	160	80	80	80	80	3,800	*0*
Phase Cost Sub-Total	$0	$352,000	$0	$108,000	$0	$0	$0	$6,000	$12,000	$6,000	$6,000	$6,000	$6,000	$285,000	*$787,000*
WARRANTY PHASE															
Servers															
Network															
Database															
Interface Coding															
Application															
Testing															
Phase Sub-Total in Hours	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Phase Cost Sub-Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
CLOSEOUT PHASE															
Project Management															
Phase Sub-Total in Hours	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
Phase Cost Sub-Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	*$0*
Project Capital Labor Hours Total	0	4,160	0	1,640	0	0	0	160	360	200	120	160	160	4,160	1,800
Project Capital Labor Cost Total	$0	$416,000	$0	$123,000	$0	$0	$0	$12,000	$27,000	$15,000	$9,000	$12,000	$12,000	$312,000	$938,000
Departmental Totals	$0	$416,000					$123,000						$87,000	$312,000	*$938,000*

JMR Manual Meter Reading
Estimated Capitalized OPR Labor (real $)

	OPR Labor					
	Routers (6)	Temporary Meter Readers (10)			Tester	Phase Total
Rate per Hour w/o OH			$25			
PLANNING PHASE						
Project Management						
Servers						
Network						
Database						
Interface Coding						
Application						
Testing						
Phase Sub-Total in Hours	0	0	0	0	0	*0*
Phase Cost Sub-Total	$0	$0	$0	$0	$0	*$0*
DESIGN PHASE						
Project Management						
Meter Reading						
Training	960	400				
Routing						
Interface Design						
Configure Application						
Application						
Testing						
Phase Sub-Total in Hours	960	400	0	0	0	*1360*
Phase Cost Sub-Total	$24,000	$10,000	$0	$0	$0	*$34,000*
EXECUTION PHASE						
Project Management						
Meter Reading		20,800				
Training						
Routing	24,960					
Interface Coding						
Application						
Testing						
Interface Coding						
Interface Testing						
Network Installation						
Configure Application						
Phase Sub-Total in Hours	24,960	20,800	0	0	0	*0*
Phase Cost Sub-Total	$624,000	$520,000	$0	$0	$0	*$1,144,000*
WARRANTY PHASE						
Routing	1920	3600				
Network						
Database						
Interface Coding						
Application						
Testing						
Phase Sub-Total in Hours	1920	3600	0	0	0	*5520*
Phase Cost Sub-Total	$48,000	$90,000	$0	$0	$0	*$138,000*
CLOSEOUT PHASE						
Project Management						
Phase Sub-Total in Hours	0	0	0	0	0	*0*
Phase Cost Sub-Total	$0	$0	$0	$0	$0	*$0*
Project Capital Labor Hours Total	27,840	24,800	0	0	0	6,880
Project Capital Labor Cost Total	$696,000	$620,000	$0	$0	$0	$1,316,000
Departmental Totals					$1,316,000	*$1,316,000*

JMR Manual Meter Reading
Estimated Annual O&M (real $)

Item	2006	2007	2008	2009	2010	Comments
Meter Readers	$330,250	$660,500	$990,750	$1,321,000	$1,321,000	20 FTEs by 2009
Supervisor	$0	$0	$0	$98,000	$98,000	
Growth Meter Readers			$66,000	$66,000	$66,000	1 FTE per year based on 3% customer growth
Labor Subtotal	**$330,250**	**$660,500**	**$1,056,750**	**$1,485,000**	**$1,485,000**	
Truck Replacement	**$80,000**	**$80,000**	**$80,000**	**$80,000**	**$80,000**	
ANNUAL O&M TOTAL	***$410,250***	***$740,500***	***$1,136,750***	***$1,565,000***	***$1,565,000***	

Rates and Regulatory Affairs
Facsimile: 503.721.2532

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June 22, 2006

Public Utility Commission of Oregon
550 Capitol Street, N.E., Suite 215
P.O. Box 2148
Salem, Oregon 97308-2148

Attn: Vikie Bailey-Goggins
Administrator, Regulatory Operations Division

RE: Docket UE 180; Staff Request No. 6-7

NW Natural submits the following response to Staff's request for information in the above-referenced matter.

6. Please state whether NW Natural is aware of any advanced metering infrastructure (AMI) system that would work with the AMI system Portland General Electric (PGE) proposes in PGE/800 such that PGE would be able to read NW Natural's meters in the joint meter reading area and send the information to NW Natural. If the company is aware of any such AMI system, please explain:

    a. The types of modifications to PGE's proposed AMI system that would be required to provide the capability of reading NW Natural's meters remotely.

    NW Natural Response: It is NW Natural's understanding that PGE has not yet selected a specific AMR system and has been testing different vendor technologies over the past several years. NW Natural previously investigated its own AMR technology choices prior to moving forward with its AMR installation project for the non-joint meter reading areas, but it has not conducted specific operational or financial analyses to determine whether a joint automatic meter reading solution with PGE is feasible since the feasibility of such an option is entirely dependent on PGE's choice of technology. Given the successful relationship that exists as a result of the joint meter reading project, NW Natural would certainly be willing to work with PGE to determine if there is an AMI system capable of cost-effectively reading NW Natural's gas meters and PGE's electric meters while performing all the necessary functions required of an electric AMI system.

    b. The estimated costs of modifications outlined in a.

    NW Natural Response: Unknown at this time.

c. The types of modifications to NW Natural's meters and related systems that would be required.

   NW Natural Response: Unknown at this time.

d. The estimated costs of modifications outlined in c.

   NW Natural Response: Unknown at this time.

e. NW Natural's assessment of whether such a system would provide net benefits to PGE and NW Natural ratepayers over a 20-year period.

   NW Natural Response: As previously submitted in response to DR 4, NW Natural has not performed a revenue requirement analysis for an automated meter reading system to read gas meters in the joint meter reading area.

7. With regard to NW Natural's response to Staff Data Request No. 1, please explain whether NW Natural could avoid the manual meter reading expenses outlined in the company's response by coordinating the timing of installation of PGE's proposed AMI system and NW Natural's separate installation of an automated meter system in the joint meter reading area.

   NW Natural Response: Should PGE proceed with an AMI installation that is not technically compatible and economically attractive in comparison to NW Natural's own AMR options, regression to traditional manual meter reading could be avoided through the coordinated installation of independent AMI/AMR systems. By working with PGE and integrating the conversion schedules of the two projects, NW Natural could avoid having to revert to traditional meter reading routes for any length of time, and minimize the impact of meter route and billing cycle changes on customers. This is just one of the options that would be considered should PGE elect to move forward with their AMR project.

Please call if you have questions.

Sincerely,

NW NATURAL

C. Alex Miller, Director
Regulatory Affairs & Forecasting

cc: Stephanie Andrus

June 27, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated June 8, 2006
Question No. 497

Request:

Please state whether PGE is aware of any advanced metering infrastructure (AMI) system that would work with the AMI system proposed in PGE/800 such that PGE would be able to read NW Natural's meters in the joint meter reading area and send the information to NW Natural. If the company is aware of any such AMI system, please explain:

a. **The types of modifications to PGE's proposed AMI system that would be required to provide the capability of reading NW Natural's meters remotely**
b. **The estimated costs of modifications outlined in a.**
c. **The types of modifications to NW Natural's meters and related systems that would be required**
d. **The estimated costs of modifications outlined in c.**
e. **PGE's assessment of whether such a system would provide net benefits to PGE and NW Natural ratepayers over a 20-year period**

Response:

General assumptions relevant to answers below
In order to enable PGE's AMI system to collect meter readings from NWN gas meters, NWN would contract separately with the AMI vendor for communication modules suitable for their meters. It is possible, for technical reasons, that NWN may have to inform PGE's AMI vendor of their interest prior to hardware being manufactured for PGE, to avoid unnecessary costs. Further, NWN would own, install, and maintain all hardware referenced in question "c" below.

a. Any AMI System PGE chooses will have three different but generic types of components: 1) the customer premise hardware, 2) the AMI network consisting of field-based communication equipment and third party communication services that transmit data between the meters and utility, and 3) computers and vendor software in the utility's operations center (each addressed below). Most AMI systems today provide a means for automated data collection of both gas and electric meters. In all cases, automated gas metering is enabled by attaching a special module on the gas meter. The module on the gas meter must have a communication radio that is compatible with the AMI system that PGE selects. In most cases, the gas radio communicates with a device installed in the electric meter. The gas data are then transferred to the field-based collectors owned by PGE using the same communication method PGE uses to collect the electric meter data.

One vendor PGE is considering requires additional hardware to be included inside the electric meter to enable wireless communication with the gas meter. For a mass deployment like that being considered by NWN, this would add significant costs to NWN's project and complicate PGE's maintenance procedures. PGE's other AMI vendors do not have this requirement, but instead include a communication device that can talk directly with a compatible module on the gas meter.

Retrieving gas meter information from a large number of meters increases the total data that must be managed by the AMI network. In many AMI systems, the field-based data collectors (also known as network "take-out points") have upper limits on how much data they can process. Consequently, adding a large number of gas meters might require additional collectors to be installed. Further, each additional collector creates the need for additional maintenance and recurring cost to transmit the data from the field to the utility.

AMI systems vary in how they enable meter data collection. Some systems would allow NWN to collect just their meter data directly from the field-based collector points, but other systems are designed such that all communication in the AMI system must be managed by a single back office computer. In the latter case, PGE's software license and back office computers may need to be modified in size and configuration to accommodate collecting NWN's meter data.

b. PGE cannot estimate these costs without selecting a specific AMI vendor and without identifying a specific business process with NWN. We believe, however, that absent a rigorous analysis, PGE's incremental costs could be approximately \$1 - \$3 million excluding additional hardware in the electric meter.

c. The most important requirement is the availability, from the AMI vendor, of a communication module in a variety of physical formats ("form factors") so they can be attached to a wide variety of gas meters owned by NWN. In most cases, these AMI modules, if available, would be installed like the "drive-by" communication module NWN is installing now in the non-joint area. Systems modifications at NWN would depend on both the specific vendor PGE selects and the business processes that would be finalized between PGE and NWN.

d. PGE has no information on which to base an estimate.

e. 80% to 90% of the cost in any AMR/AMI system is the installed cost of hardware at the customer premise. From a PGE-customer perspective, NWN would pay at least 100% of the incremental cost to collect the data on the network, to store the data on computers, and to manage its delivery to NWN. In a negotiated agreement with NWN, it may be possible to create a solution in which NWN pays more than the incremental cost, but less than the cost if it were to perform this function solely on its own. To this extent, there might be a small net benefit to PGE customers. Because NWN is only planning to automate monthly data collection, there would be no cost savings to PGE customers on the investment made to manage daily and interval data.

From the NWN customer perspective, PGE believes that additional benefits are unlikely because a two-way AMI gas module that is compatible with PGE's system, would have to be competitively priced with NWN's present one-way, drive-by communication module (for various technical reasons, this seems unlikely). Ultimately, neither PGE nor NWN can estimate a net benefit, if any, for both sets of customers unless NWN receives a price quote from the AMI vendor that PGE selects.

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 372

Request:

Please refer to PGE/800, Hawke-Carpenter/Tooman/4-5. Please explain the steps PGE is taking to work with NW Natural to minimize costs for customers of both utilities related to advanced metering installation and ongoing meter reading.

Response:

As part of the Joint Meter Reading (JMR) partnership, PGE and NWN work together to reduce meter reading costs for both utilities, in areas where service territories overlap. Within the impacted area, meter reading routes are continually optimized to ensure that one utility reads both meters during a single visit.

NMW has selected its automated metering vendor and will soon begin installations outside of the JMR areas. In late 2006, when PGE has selected its AMI vendor (depending on OPUC approval of PGE's proposed AMI system), PGE expects to collaborate with NWN to develop a detailed installation plan that minimizes costs in the JMR area. At this time, PGE is not aware of NWN's plans if PGE either installs or does not install AMI in the JMR areas.

July 3, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated June 26, 2006
Question No. 514

Request:

In Special Condition 9 of Schedule 75, please explain what is meant by "not less than two calendar years prior notice" when referring to a change in Baseline Demand related to modifications in generating capacity or generation operations. Provide an example timeline including the date the customer requests to change Baseline Demand under Special Condition 9 and the effective date for the revised Baseline Demand.

Response:

Not less than two calendar years prior notice means that all requests for changes in Baseline demand will take effect January 1 of a calendar year at least two years subsequent to the request. As an example, should a partial requirements customer request a change in Baseline Demand July 1, 2007, PGE would consider the effective date of the change in Baseline Demand to be January 1, 2010.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 404

Request:

Please explain why PGE proposes under Special Condition 9 of Schedule 75 not to allow a customer to provide notice more frequently than every two years for a change in Baseline Demand due to modifications in generating capacity or generation operations.

Response:

Within Special Condition 9 PGE proposes that a customer be able to provide subsequent notice no earlier than two years from the last notice because PGE wishes to maintain the integrity of the notice requirements and to be able to effectively plan for meeting the load requirements of its customers. Absent this provision, a large Schedule 75 customer could on a weekly, or perhaps even more frequent basis, attempt to either increase or decrease their baseline demand by large increments. These frequent increases or decreases in baseline demand could make it more difficult for PGE to plan to meet customer load in a cost effective manner.

July 3, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated June 26, 2006
Question No. 515

Request:

In Special Condition 9 of Schedule 75, please explain what is meant by "no earlier than two years from the last notice that resulted in a change to the Customer's Baseline Demand" when referring to subsequent notices by the customer under this special condition. Provide an example timeline including the customer's last request to change Baseline Demand under Special Condition 9, the customer's subsequent request under this special condition, the date PGE accepts the customer's subsequent request, and the effective date of the revised Baseline Demand under the subsequent request.

Response:

In Special Condition 9 the statement "no earlier than two years from the last notice that resulted in a change to the Customer's Baseline Demand" means that subsequent requests by the partial requirements customer for a change in Baseline Demand will be granted two years after the previous request for a change in Baseline Demand was granted. As an example, should a partial requirements customer request a change in Baseline Demand July 1, 2007, PGE would consider the effective date of the change in Baseline Demand to be January 1, 2010. Any subsequent requests for a change in Baseline Demand between July 1, 2007 and December 31, 2009 would take effect not before January 1, 2012.

May 4, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 1.3
Dated April 20, 2006
Question No. 003

Request:

Please describe how PGE would adjust its power supply in response to a notice of change in baseline demand, assuming that the notice requirement was 3 months, 6 months, 1 year, or 2 years. Also, please explain how other customers would be harmed under each scenario.

Response:

Depending on whether the Baseline Demand is increased or decreased, PGE would expect to either acquire additional energy or divest itself of power supply. If the notice of change in Baseline Demand is short (i.e., 3, 6 or 12 months) then PGE would expect to adjust resource balances with short term market purchases or sales to match the change in the Baseline Demand. The particular supply actions PGE may take depend on a number of factors including other forecast load and supply changes and the available pricing option selected by the customer (e.g., daily price, monthly price, cost of service). If the customer's notice is received prior to the annual RVM resetting of rates, other customers are affected by the reallocation of resources under the mechanism. For example, an increase in Baseline Demand essentially spreads the economic value of PGE's existing resources over additional kWhs. Under current market conditions, this tends to increase rates of other customers. If notice is received after the RVM process, PGE's earnings are negatively affected since the total economic value of existing resources provided to customers exceeds the actual total amount available. Two year notice helps ensure that decisions are long-term in nature and not based on short-term economics. In addition it is consistent with the notice required in Schedule 483 and with the type of information typically available on new loads (See PGE's response to ICNU Data Request No. 1.4).

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 408

Request:

Please explain why PGE believes notification requirements for changing Baseline Demand under Schedule 75 should be the same as those for returning to the cost-of-service rate for Schedule 483/489 customers choosing the *five*-year opt-out.

Response:

PGE believes that both long-term direct access customers served under the five-year provisions of Schedules 483/489 and self-generating customers (for the portion of their load supplied by self-generation) have severed their relationship to cost of service and its associated transition charges or credits. Restrictions on movement between these options and cost of service are necessary to ensure that customers do not have a free option to receive cost of service prices when it includes transition credits but exit cost of service when it includes transition charges. This more consistently reflects the implicit long-term supply commitments made between partial requirements customers and PGE.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 409

Request:

Please explain why PGE believes notification requirements for changing Baseline Demand under Schedule 75 should *not* be the same as those for returning to the cost-of-service rate for Schedule 483/489 customers choosing the *three*-year opt-out.

Response:

The fixed three year opt-out has a required term of service of three years (please see PGE Exhibit 1302 page 161.) Therefore, customers choosing this option are providing a de facto three year notice provision to PGE. PGE initially proposed this option at the behest of Energy Service Suppliers (ESSs), customers and the OPUC Commission. Attachment 409-A contains the OPUC Staff recommendation that states that "For planning purposes, PGE assumes that these customers will return to cost of service after their contract term expires." PGE believes that the increased notice requirement de facto imposed on the Schedule 483/489 customers is a reasonable balancing of interests between customers, ESSs and PGE.

July 19, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated July 6, 2006
Question No. 519

Request:

During the two calendar-year waiting period following a request to increase Baseline Demand under Special Condition 9, please explain the energy options available to a Schedule 75 customer for the amount of energy above the previous Baseline Demand that results from a change in generator capacity or generation operations.

Response:

During the two calendar-year notice period, the Schedule 75 customer may receive energy from PGE under the energy options available in Schedule 76R for the amount of energy above the previous Baseline Demand resulting from a change in generator capacity or operations. The customer may also move to direct access service and obtain energy from an ESS under the provisions of Schedules 575 and 576.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 405

Request:

Please state whether PGE believes there is a threshold below which a customer may request minor changes (up or down) in Baseline Demand due to changes in generating capacity or generation operations that would not trigger the Company's proposed two-year notice requirement. If PGE believes such a threshold may be reasonable, please state the threshold level and the factors PGE considered in making that determination. If PGE believes no change in Baseline Demand is minor enough to be accommodated by the Company without the proposed two-year notice requirement, please explain why.

Response:

PGE believes that all requests for changes in Baseline Demand due to changes in generating capacity or generating operations should fall under the provisions of the two-year notice requirement. PGE believes that this is necessary to maintain the integrity of the notice requirement. To do otherwise could yield a series of requests for incremental changes in baseline demand over a limited time period.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 406

Request:

Please explain how PGE would treat a request by a Schedule 75 customer to increase Baseline Demand due to a long-term, catastrophic failure of the customer's generator. Include any notice requirements.

Response:

PGE would require a two-year notice requirement to increase Baseline Demand in the circumstances described above. Any additional load requirements that the customer wished for PGE to serve would be met under the provisions of Schedule 76.

May 4, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 1.4
Dated April 20, 2006
Question No. 004

Request:

Please explain why an increase in baseline demand from a partial requirements customer should be treated differently from a new load.

Response:

A partial requirement customer's contractually specified Baseline Demand may increase as a result of from an increase in either a partial requirements customer's load (that is, on-site energy usage exclusive of generation) or a decrease in on-site generation output, subject to notice requirements as described in Schedule 75, Condition 9. Schedule 75 differentiates between these two reasons for changes to Baseline Demand. The Schedule 75 Baseline Demand establishes the load normally supplied by the Company.

As described in Schedule 75, load is served by the Company up to the Baseline Demand at the Cost of Service prices set out in Schedule 89. Increases in the customer's load net of generation, caused by an increase in energy usage by on-site equipment with no change in generation characteristics, are effectively treated the same as new load and will increase the contractual Baseline Demand (Schedule 75, Special Condition 8). In reality, PGE is generally aware of significant new loads well before they come on line. This is due to our need to adequately plan to meet the load not only from a supply view point but also in terms of delivery of the power. The advance knowledge is often at least two years.

A change in the customer's net load resulting from on-site generation output reduction is not a new load but a shift in generation source initiated by the customer. The customer's Baseline Demand can then be changed with two year notice. As explained in Exhibit 1300, run by changes in the Baseline Demand related to use of on-site generation or utility cost of service supply, does not equitably balance the impact of this optionality with cost impacts on other customers.

July 19, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated July 6, 2006
Question No. 518

Request:

Please explain how PGE would apply Special Conditions 8 and 9 to a Schedule 75 customer's request to reduce Baseline Demand when a customer installs additional generating capacity, including any notification requirements.

Response:

Schedule 75, Special Condition 9 provides that a customer give two calendar year notice to modify the Baseline Demand associated with the installation of additional generation capacity. Special Condition 8 is not applicable to this scenario.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 401

Request:

Please explain how PGE would treat a request by a Schedule 75 customer to increase Baseline Demand due to the addition of a production line, which increases the customer's on-site load. Include any notification requirements.

Response:

PGE would grant the customers request to increase their Baseline Demand in the situation described above. Customers are required to provide notice of material changes in load (See Rule C 4(C) (5)) to allow PGE to determine whether changes in service facilities are needed. As discussed below, PGE is typically aware of significant load changes well in advance.

As described in Schedule 75, load is served by the Company up to the Baseline Demand at the Cost of Service prices set out in Schedule 89. An increase in the customer's load net of generation caused by an increase in energy usage by on-site equipment with no change in generation characteristics is effectively treated the same as new load and will increase the contractual Baseline Demand (Schedule 75, Special Condition 8). In reality, PGE is generally aware of significant new loads well before they come on line. This is due to our need to adequately plan to meet the load not only from a supply view point but also in terms of delivery of the power. The advance knowledge is often at least two years.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 402

Request:

Please explain how PGE would treat a request by a Schedule 75 customer to decrease Baseline Demand due to reduced business sales, which decrease the customer's on-site load. Include any notification requirements.

Response:

PGE would grant a Schedule 75 customer's request to decrease their Baseline Demand due to a permanent decrease in on-site load. There would be no notification requirements however PGE may not be able to accommodate the request until the conclusion of the current cycle billing process.

As described in Schedule 75, load is served by the Company up to the Baseline Demand at the Cost of Service prices set out in Schedule 89. A decrease in the customer's load net of generation caused by a decrease in energy usage by on-site equipment with no change in generation characteristics is effectively treated the same as a customer specific load reduction and will decrease the contractual Baseline Demand (Schedule 75, Special Condition 8).

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 398

Request:

Please define the term "permanent energy efficiency measures" as used in Special Condition 8 of Schedule 75, including the types of measures included and their assumed useful lives.

Response:

"Permanent energy efficiency measures" as used in Special Condition 8 of Schedule 75 refers to energy efficiency measures expected to be in place indefinitely. Permanent energy efficiency measures generally include the installation of equipment that reduces the energy requirements of end-uses and may broadly include equipment changes for lighting, heating and motor drives.

July 3, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated June 26, 2006
Question No. 511

Request:

Please define the term "removal of equipment" as used in Special Condition 8 of Schedule 75. Specify the types of equipment included — for example, end-use equipment only, on-site generation equipment only, or both. Please explain whether such equipment removal must be permanent and, if so, how permanency will be determined.

Response:

Removal of equipment as used in Special Condition 8 of proposed Schedule 75 refers to both end-use equipment and on-site generation equipment. The equipment removal must be permanent. Permanency is defined as removal that is expected to last indefinitely.

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July 3, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated June 26, 2006
Question No. 513

Request:

Please explain how PGE would apply Special Conditions 8 and 9 to a customer's request to increase Baseline Demand when a customer puts in place permanent energy efficiency measures that reduce on-site load to a level at which the customer determines it can no longer operate its on-site generation, or it must operate the generators at a lower level than before such measures were installed.

Response:

In both instances, the partial requirements customer would be allowed to decrease their baseline demand without two years notice, but would not be allowed to increase their baseline demand without at least two years notice. In the first instance, should the partial requirements customer permanently remove all their generating equipment the two year notice would not apply; the customer would no longer be a partial requirements customer and would return to the appropriate tariff Schedule.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 397

Request:

Please define the term "modified" as used in Special Condition 8 of Schedule 75, including whether the term refers to increases as well as decreases in Baseline Demand.

Response:

The term "modified" means a change in the Baseline Demand from the then current level specified in the service agreement and refers to both Baseline Demand increases as well as decreases.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 399

Request:

Please define the term "load shedding" as used in Special Condition 8 of Schedule 75, including the types of actions included and their assumed durations.

Response:

"Load shedding" refers to equipment installed by the Schedule 75 customer that enables the customer to reduce on-site load instantaneously in the event of a failure in its generator(s) such that there would be no additional unscheduled load requirements placed upon PGE. Once the load shedding requirements have been met, the Schedule 75 customer has the option to request Economic Replacement Power under the provisions of Schedule 76R.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 400

Request:

If a Schedule 75 customer participates in a PGE demand response program — Demand Buyback, for example — how does load shedding under that program affect the customer's Baseline Demand under Schedule 75?

Response:

Voluntary participation in PGEs Demand Buyback tariff does not alter the Schedule 75 customer's Baseline Demand. The maximum eligible load for a Schedule 75 customer under PGE proposed Schedule 86 Demand Buyback is the Schedule 75 Baseline Demand.

May 16, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated May 3, 2006
Question No. 407

Request:

Please explain whether a Schedule 75 customer can sell all or part of its generator output to a third party. If not, please explain why, including how such a provision could harm other customers or shareholders, and cite the condition in the tariff that PGE believes prohibits such sales.

Response:

Schedule 75 as its name states, is a Partial Requirements Schedule; therefore it is made available to Large Nonresidential Customers *supplying all or some portion of their load by self-generation operating on a regular basis*. If a customer is selling all of its generation output to a third party and purchasing its power requirements from PGE, it is not a partial requirements customer and thus is not served under Schedule 75.

A Schedule 75 customer can sell part of its generator output to a third party provided it has met all of its energy requirements through self-generation and does not take energy from PGE.

A Schedule 75 customer may not sell its generator output while simultaneously receiving energy from PGE because to do so allows the customer to unfairly arbitrage between power markets and the PGE cost of service rate. For example if the Schedule 75 customer were to request an additional 50 MWa (438,000 MWH and market prices were anticipated to be $75 per MWH while PGE's embedded cost of service energy supply was anticipated to be $55 per MWH, other customers would bear the burden of this cost increase in energy supply. If market prices later fell below the PGE rate and assuming that the customer's cost of generation was less, the customer would then stop selling in the market and utilize the power it generated. Again, PGE's other customers would suffer.

OPUC Staff has previously recognized that changes to Schedules 75 and 575 should be considered. Attachment 407-A contains the OPUC Staff memo that states that "..,we agree with PGE that changes to Schedules 75 and 575 should be considered to protect other customers from 'precipitous decisions by partial requirements customers to switch from self generation to cost of service'."

Conditions in the tariff that prohibit the Schedule 75 customer from selling its output while simultaneously receiving energy from PGE at a COS energy rate are specified in the following places within the proposed Schedule 75 tariff:

75-1 under Applicability; To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis.

75-2 under Baseline Demand; Baseline Demand is the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating.

75-3 under Baseline Energy; Unless otherwise agreed to, the Baseline Energy is the Energy normally supplied by the Large Nonresidential Customer when the Customer's generator is operating.

Rule F (E.) Restrictions on Resale.

CASE: UE 180/UE 181/UE 184
WITNESS: J. R. Gonzalez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Direct Testimony

August 9, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is JR Gonzalez. I am employed by the Public Utility Commission of Oregon as Program Manager, Safety and Reliability section of the Utility Program. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/701.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My testimony addresses one issue related to Portland General Electric Company's (PGE's) proposal to install advanced metering infrastructure (AMI), the role of implementation plans in achieving the operation and maintenance (O&M) benefits the company's proposed AMI system is expected to deliver. Specifically, my testimony supports staff witness Schwartz's recommendation that PGE should file with the Commission detailed implementation plans that would reasonably be expected to achieve the O&M benefits assumed in the company's AMI analysis in PGE/800.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Staff Exhibit 702, responses to selected Staff data requests, consisting of 2 pages.

IMPLEMENTATION PLANS FOR ADVANCED METERING INFRASTRUCTURE

Q. PLEASE SUMMARIZE YOUR EXPERIENCE WITH AMI, INCLUDING DEVELOPMENT, REVIEW AND EXECUTION OF IMPLEMENTATION PLANS TO ACHIEVE O&M SAVINGS.

A. As manager of the Metering and Distribution Transformer Department at Puget Sound Energy (PSE), I participated in preparing and evaluating the company's Automated Meter Reading (AMR) business case, and managed an AMR pilot project at Mercer Island in 1995 and a Network Meter Reading (NMR) pilot project in Olympia in 1996. PSE was able to bill directly from the NMR system in Olympia three months after completion of the pilot.

In 1997, I joined CellNet Data Systems to fully implement the NMR project at PSE as the Logistics and Deployment Manager. The PSE deployment program became CellNet's benchmark for three additional NMR projects. In 1-1/2 years CellNet successfully deployed more than 500,000 gas and electric meters with customers billed directly from the NMR network.

In December 1998, I joined the international arm of CellNet Data Systems with Bechtel Enterprises in Europe as their Director of International Program Management. In that capacity I developed the strategic deployment plan for Europe with the executive team; led the effort in adapting CellNet's technology, while establishing parameters for the UK project and Europe; led the team in the technology transfer for manufacturing LAN's Micro Cell Controller (MCC) from Cellnet to BCN; recruited a team with the right mix of skills and expertise to implement the project; and developed the organizational structure, project schedule, budgets and human resources required to carry out the proposed project with British Gas and London Electricity. Also, I trained management staff in program management and high volume deployment of endpoints and the LAN network.

Q. PLEASE EXPLAIN THE IMPORTANCE OF IMPLEMENTATION PLANS FOR ACHIEVING O&M SAVINGS THROUGH AMI.

A. AMI fully and properly implemented will bring direct tangible savings such as reduced costs for labor, vehicles and equipment; reduced power theft; reduced time from read to billing customers, which improves cash flow; and other savings. In addition, the AMI network can provide a solid base for implementation of other savings and operational efficiencies. However, ensuring that the AMI is capable of providing that base requires advance planning and foresight in the implementation and operation and maintenance of the network.

There are synergies in many of the efficiencies the AMI network provides. For example, the two-way communication system supports implementation of remote disconnect/reconnect services, cut in/cutout services, data for distribution planning programs, and demand response programs. The implementation of these programs will bring substantial savings, but to implement them will require financial resources as well.

PGE should provide its implementation plans for such programs, as well as others, for two primary reasons: 1) Staff wants to weigh the full cost effectiveness of the proposed programs, which programs PGE should have studied during its research/study and evaluation phase, in preparation of its business case, and 2) If not studied or planned for at this stage, including estimated budgets, such programs will be more difficult to implement in the future.

Q. WHAT DO SUCH IMPLEMENTATION PLANS TYPICALLY INCLUDE?

A. First, implementation plans should include all the necessary resources to properly and successfully implement the programs. Such resources will involve facilities, tools and equipment, staff with the required skills and experience in the various program areas, and hardware (IT and others). Second, the plans provide details on the required processes and procedures to carry out AMI-enabled programs, including all associated costs and timelines for each program. Savings to be achieved with implementation for each program also should be presented.

Examples of some of the programs are a) distribution Planning, which entails proper sizing of distribution transformers, load balancing of substation feeders, better fusing and coordination analysis and settings, etc.; b) power outage management, response and restoration; c) system-wide load studies and performance analysis; and d) demand response programs such as load control of heating, ventilating and air-conditioning systems and water heating, time-varying pricing programs, and voluntary power curtailment programs. These are in addition to the more obvious programs such as cut ins/cut outs, remote disconnects and reconnects, and tapping greater capabilities and efficiencies at customer call centers.

Q. HAS PGE DEVELOPED IMPLEMENTATION PLANS TO ACHIEVE THE O&M SAVINGS IT EXPECTS FROM ITS PROPOSED AMI SYSTEM?

A. No. *See* PGE's response to Staff Data Request No. 363; Staff/702, Gonzalez/1-2.

Q. WHEN IS THE APPROPRIATE TIME TO DEVELOP SUCH IMPLEMENTATION PLANS?

A. PGE has dedicated a lot of time and resources to research, study and preparation of the business case for the AMI program. All possible and doable efficiencies to be achieved with the AMI program should have been identified with its implementation cost and savings during this research and study period. The company did not include in its filed testimony and responses to staff data requests all of the savings that can be achieved.

Q. WHAT ARE THE CONSEQUENCES OF NOT HAVING IMPLEMENTATION PLANS IN PLACE PRIOR TO AMI INSTALLATION?

A. The consequences are that the full range of cost-saving programs that AMI can enable may not be implemented in the future. For example, the company's Network Operating System will not be designed to accommodate programs that have not been considered. Some of the immediate consequences are a) compromised planning and operational efficiencies, b) lost savings, and c) higher cost for future program planning and implementation efforts. Another major consequence in implementing programs after the fact, with no plans prepared during the design, development and implementation phases, is that future programs may not be fully compatible with PGE's AMI. Such new programs may create conflicts and require changes of the Network Operating System in order to support the new programs, impacting the operation of other implemented programs.

It makes sense to plan all programs to be implemented as a complete package during the planning and design phase, so all common data and control elements are identified and programmed properly, including the firmware and hardware integration. For example, one work station may be able to support multiple programs that share the same data streams or command capabilities.

Q. CAN PGE CUSTOMERS BE ASSURED THAT THE COMPANY WILL ACHIEVE THE ANNUAL O&M BENEFITS STATED IN PGE/800 IN THE ABSENCE OF SUCH IMPLEMENTATION PLANS?

A. It will make it less likely.

Q. PLEASE SUMMARIZE WHY YOU SUPPORT STAFF WITNESS SCHWARTZ'S RECOMMENDATION THAT PGE FILE IMPLEMENTATION PLANS WITH THE COMMISSION.

A. PGE is requesting rate consideration from the Commission for its AMI proposal. To properly consider the true benefit of AMI to PGE's ratepayers, Staff must be able to evaluate the entire program with its full capabilities, cost and benefits.

Q. PLEASE EXPLAIN THE LEVEL OF DETAIL YOU WOULD EXPECT TO SEE IN A WELL PREPARED IMPLEMENTATION PLAN DESIGNED TO ACHIEVE THE O&M SAVINGS DESCRIBED IN PGE/800.

A. The company should present current operational processes with associated actual costs, and for each process the company should identify the improvements that will be achieved with AMI implementation, including identification and quantification of those efficiencies not achievable or possible without AMI. The company also should identify for the life of the AMI system for each operational process all needed facilities, staff (with the required skills and experience in the various program areas), hardware (IT and others), processes and procedures, program plans with all associated costs and implementation timelines, and operation and maintenance requirements.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 180/UE 181/UE 184
WITNESS: J. R. Gonzalez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification Statement

August 9, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	J.R. Gonzalez
EMPLOYER:	Oregon Public Utility Commission
TITLE:	Program Manager, Utility Safety and Reliability
ADDRESS:	550 Capitol Street NE #215 Salem, OR 97301-2551
EDUCATION:	Master in Business Administration (1984) – City University Bachelor of Science, Mechanical Engineering (1981) - Portland State University Associate Degree in Machines and Motors (1976) - Campinas State University
PROFESSIONAL LICENSES:	Registered Professional Engineer in the States of Oregon and Washington
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission since May 2004 as program manager of Utility Safety and Reliability. Before coming to the PUC, I spent two years in my own consulting firm where I supported Rogers International Consulting, L.L.C. with the Tropical Hardwood Project for environmentally safe wood poles and crossarms in partnership with EPRI. Prior to my consulting activities I worked eight years on wireless telecommunications and telemetry programs in Europe, Latin America and Canada. From 1981 through 1997, I worked at Puget Sound Power & Light Co, now Puget Sound Energy, where I started as an engineer in power generation. Next, I worked in transmission and distribution engineering, then customer programs including conservation, voltage stability and power quality. After that, I worked in transmission and distribution operations, where I as the lead consulting engineer managing PSE's maintenance programs. I performed several failure investigations of large equipments, supported the standardization process of all commodities at Puget Power, audited field practices and commodity suppliers, and wrote work practices. Another area I was actively involved with was training programs for operations and engineering personnel. My last position at PSE was manager of the metering, distribution transformers, and test, repair and calibration department.

CASE: UE 180/UE 181/UE 184
WITNESS: J. R. Gonzalez

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 702

Exhibits in Support of Direct Testimony

August 9, 2006

May 9, 2006

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to OPUC Data Request
Dated April 24, 2006
Question No. 363

Request:

Please provide PGE's implementation plan for the following items, including but not limited to timeline, costs and savings.

a. **Demand benefits (demand response programs and direct load control)**
b. **Outage reporting**
c. **Outage detection**
d. **Restoration**
e. **Better distribution planning**
f. **Economic benefits (cost savings)**
g. **Functional benefits for customers and employees (convenience, safety)**

Response:

a. PGE is currently planning to include demand-side resources in its 2006 Integrated Resource Planning process, including direct load-control programs. The outcome of the resource planning process will inform any subsequent implementation plan.
b. PGE has not developed a timeline or estimated the costs and savings associated with outage reporting. Cost/benefit analyses might take place as early as 2008, but system automation, if cost effective, would not likely occur before 2010. For more information on outage reporting, see PGE's response to OPUC Data Request Nos. 364 and 367.
c. PGE has not developed a timeline or estimated the costs and savings associated with outage detection. Cost/benefit analyses might take place as early as 2008, but system automation, if

d. cost effective, would not likely occur before 2010. For more information on outage detection, see PGE's response to OPUC Data Request Nos. 364 and 367.

e. PGE has not developed a timeline or estimated the costs and savings associated with restoration. Cost/benefit analyses might take place as early as 2008, but system automation, if cost effective, would not likely occur before 2010. For more information on restoration, see PGE's response to OPUC Data Request Nos. 364 and 367.

f. PGE has not developed a timeline or estimated the costs and savings associated with better distribution planning. However when the AMI system is deployed and resources are available, PGE plans to evaluate the following concepts for improved capital utilization based on additional information provided by the AMI system:
   - By aggregating meter data served by specific substations, PGE could identify alternative configurations of feeder lines with adjacent substations so as to potentially defer upgrades on substations approaching service limits.
   - By aggregating meter data served by a specific transformer, PGE could identify under- or over-utilized transformers and replace them with ones having the correct capacity.

g. For detailed information on cost savings, see PGE's response to OPUC Data Request No. 374, Attachments 374-A, 374-B, 374-E, and 374-F.

h. With the exception of "customer selected due date" (CSDD), PGE has not developed a timeline or estimated the costs and savings associated with functional benefits for customers and employees. For CSDD, PGE included the following estimates in its analysis of the proposed AMI system:
   - Costs – approximately $1.5 million in IT costs to develop the CSDD program.
   - Benefits – approximately $5 million annual reduction in Working Cash rate base (see PGE's response to OPUC Data Request No. 374, Attachment B, "O&M-Working Cash" tab.

CASE: UE 180/UE 181/UE 184
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Direct Testimony

August 9, 2006

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Maury Galbraith. The Public Utility Commission of Oregon (OPUC) employs me as a Senior Economist.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THESE PROCEEDINGS?

A. Yes. I sponsored Staff/100 in consolidated Docket Nos. UE 180, UE 181 and UE 184. My witness qualifications were provided as Staff/101.

Introduction and Summary

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I address two separate issues in this testimony. The first issue is the prudence of Portland General Electric's (PGE's) decision to build the Port Westward generating facility. The second issue is PGE's proposed power cost framework.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I address the issue of the prudence of PGE's decision to build Port Westward. I indicate that staff will make its final recommendation on the prudence of PGE's decision to build Port Westward in its rebuttal testimony scheduled for October 6, 2006. Next, I address PGE's proposed power cost framework. I summarize the company's arguments for why it needs both a forward-looking automatic adjustment clause and a retrospective automatic adjustment clause. I present staff's analysis of the proposed framework and PGE's arguments supporting the need for the automatic adjustment clauses. I also present staff's recommended power cost framework and indicate why it is preferable to PGE's framework.

Q. PLEASE SUMMARIZE STAFF'S RECOMMDATIONS REGARDING PGE'S POWER COST FRAMEWORK.

A. Staff makes the following recommendations:

- The Commission should use the design criteria for power cost adjustment mechanisms identified in Order 05-1261 to evaluate PGE's proposed power cost framework.
- The Commission should reject PGE's Annual Power Cost Variance (Annual Variance) mechanism. The Annual Variance mechanism lacks a power cost deadband and as a result does not satisfy the unusual event standard. The mechanism also lacks an earnings test deadband and therefore fails to prevent recovery if overall earnings are reasonable.
- The Commission should reject PGE's Annual Power Cost Update (Annual Update) mechanism. It is unclear if the benefits of a prospective automatic adjustment clause outweigh its regulatory burdens.
- The Commission should adopt Staff's proposed long-term power cost adjustment (PCA) mechanism. Staff's proposed PCA mechanism satisfies the unusual event and reasonable recovery standards. It also does not incent direct-access eligible customers on their choice to go direct access or remain with the company.

PGE's Port Westward Decision

Q. HAS STAFF REVIEWED PGE'S TESTIMONY ON THE PRUDENCE OF ITS DECISION TO BUILD THE PORT WESTWARD GENERATING FACILITY?

A. Yes.

Q. HAS STAFF DISCOVERED ANY ISSUES OR CONCERNS REGARDING PGE'S DECISION TO BUILD PORT WESTWARD?

A. No.

Q. WILL STAFF INVESTIGATE ANY PRUDENCE CHALLEGES TO PGE'S DECISION TO BUILD PORT WESTWARD MADE BY INTERVENORS TO THIS CASE?

A. Yes. Staff will review any prudence challenges made by intervenors in their testimony filed with the Commission August 9, 2006. Staff will provide its analysis and recommendations in its rebuttal testimony in this case on October 6, 2006.

Q. DOES STAFF HAVE ANY RECOMMENDATIONS TO MAKE REGARDING THE PRUDENCE OF PORT WESTWARD AT THIS TIME?

A. No.

PGE's Power Cost Framework

Q. PLEASE SUMMARIZE PGE'S PROPOSED POWER COST FRAMEWORK?

A. PGE's power cost framework consists of three regulatory tools: (1) the general rate case; (2) the prospective automatic adjustment clause; and (3) the retrospective automatic adjustment clause. PGE proposes to replace its annual Resource Valuation Mechanism (RVM) with the Annual Update mechanism. The Annual Update is a prospective automatic adjustment clause that would forecast normalized net variable power cost (NVPC) each year. PGE also proposes the Annual Variance mechanism to track differences between actual NVPC and the NVPC reflected in its rates.

Q. DOES PGE PROPOSE SUBSTANTIVE CHANGES TO HOW POWER COSTS WOULD BE ADDRESSED IN GENERAL RATE CASES?

A. No. PGE's testimony on this part of its proposed framework is largely a discussion of regulatory lag and normalized test period ratemaking. See PGE/400, Lesh – Niman/16-24.

Q. DOES PGE ARGUE THAT A POWER COST FRAMEWORK BASED SOLELY ON THE USE OF THE GENERAL RATE CASE IS UNREASONABLE?

A. Yes. PGE argues that the general rate case is ill suited for addressing components of power cost that can change significantly from year to year. *See* PGE/400, Lesh – Niman/9. More specifically, PGE argues that the current normalization methodologies used for thermal plant forced outage rates and for hydroelectric generation represent unacceptable risk allocations without some sort of retrospective automatic adjustment clause. *See* PGE/400, Lesh – Niman/ 21-22. PGE indicates that an Annual Variance tariff is needed:

> …to ensure that customers see most of the benefit of good plant performance and that PGE recovers most of its cost to provide power despite prudently-incurred plant outages.

See PGE/400, Lesh – Niman/21. PGE also indicates that the Commission recognized the need for a retrospective automatic adjustment clause to address variation in hydro generation in Docket Nos. UM 1071 and UE 165. *See* PGE/400, Lesh – Niman/22.

Q. PLEASE SUMMARIZE PGE'S ANNUAL POWER COST VARIANCE MECHANISM?

A. PGE's proposed Annual Variance mechanism is a retrospective automatic adjustment clause that would:

1. Track the difference between actual unit NVPC and the unit NVPC reflected in rates;[1]
2. Determine the Annual Variance by multiplying the difference between unit NVPC by the actual loads from the variance period;
3. Place ninety percent of the Annual Variance in a balancing account for later offset or amortization;
4. Employ an earnings test prior to amortization of any deferred amounts; and
5. Share with customers fifty percent of any earnings exceeding an updated return on equity (ROE) by more than 100 basis points.

[1] Unit NVPC is defined as NVPC divided by loads (i.e., NVPC per kWh). *See* PGE/400, Lesh – Niman/35.

Q. WHY DOES PGE PROPOSE AN ANNUAL VARIANCE MECHANISM?

A. PGE offers three reasons for seeking an Annual Variance mechanism. First, as I mentioned earlier, PGE argues that the risks associated with thermal plant forced outages and hydroelectric generation are unacceptable without some sort of retrospective adjustment mechanism. Second, PGE argues that it should have a retrospective adjustment mechanism because the overwhelming majority of investor-owned utilities have one. Based on the findings of a study performed by NERA Economic Consulting, PGE witnesses Lesh and Niman conclude:

> PGE's current lack of a retrospective tool for variances between forecasted and actual power costs places us in an "outlier" status among cost of service electric (or combination) utilities. This is why our framework includes the Annual Variance tariff.

PGE/400, Lesh-Niman/13. Finally, PGE argues that a retrospective adjustment mechanism is needed to provide appropriate assurance that the company's rates reflect its cost of service. Lesh and Niman state:

> Without a retrospective mechanism in the framework, neither PGE nor customers will have the assurance they should have that prices reflect cost of service.

PGE/400, Lesh-Niman/33.

Q. PLEASE SUMMARIZE PGE'S ANNUAL UPDATE MECHANISM?

A. PGE proposes a prospective adjustment mechanism to reset the NVPC component of its rates on an annual basis. PGE would use its MONET power cost model to update it normalized NVPC. PGE recommends limiting the update to changes in the following model inputs: (1) loads; (2) power, fuel, fuel transportation, and transmission/wheeling contracts; (3) forced outage rates; (4) planned maintenance outages; and (5) market forward price curves for electricity and natural gas. *See* PGE/400, Lesh – Niman/25.

Q. DOES THE ANNUAL UPDATE IMPACT THE OPERATION OF THE ANNUAL VARIANCE MECHANISM?

A. Yes. The Annual Update mechanism would reset the unit NVPC reflected in PGE's rates and the Annual Variance mechanism would track the difference between this reset unit NVPC and actual unit NVPC over the following year.

Q. WHY DOES PGE PROPOSE AN ANNUAL UPDATE MECHANISM?

A. PGE indicates that its advance power and natural gas purchasing is the primary driver of the year-to-year change in its annual NVPC. PGE has little confidence that its normal test period NVPC will be representative of its actual NVPC in the years beyond its 2007 test period. *See* PGE/400, Lesh – Niman/25-26. PGE proposes the Annual Update mechanism as a means to adjust its normal NVPC to better approximate its actual NVPC in future years. PGE argues that without the Annual Update, market-driven changes in NVPC may not be reflected in its rates on a timely basis.

Staff's Analysis of PGE's Power Cost Framework

Q. HAS STAFF TESTIFIED IN RECENT DOCKETS REGARDING CRITERIA THAT SHOULD BE USED IN CONSTRUCTING AND EVALUATING AUTOMATIC ADJUSTMENT CLAUSES?

A. Yes. In Docket Nos. UE 165 and UE 173, Staff proposed three design criteria for PCA mechanisms. First, a normal range of variation should not trigger the mechanism. Second, a PCA mechanism should not bias the overall expected level of power cost recovery. Third, a PCA mechanism should not incent direct-access eligible customers on their choice to go direct access or remain with the company.

Q. DID THE COMMISSION ESTABLISH DESIGN CRITERIA FOR HYDRO-RELATED PCA MECHANISMS IN ITS ORDER IN DOCKET UE 165?

A. Yes. In Order 05-1261, the Commission established four design criteria for hydro-related PCA mechanisms. First, a PCA mechanism should be limited to unusual events. Second, a PCA mechanism should not adjust rates if the utilities' overall earnings are reasonable. Third, a PCA mechanism should be revenue neutral. Finally, a PCA mechanism should be a long-term commitment.

Q. SHOULD THE COMMISSION APPLY THESE CRITERIA TO PCA MECHANISMS THAT TRACK ANNUAL TOTAL NVPC?

A. Yes. Staff believes the criteria established in Order 05-1261 are directly applicable to the evaluation of comprehensive PCA mechanisms. *See* Staff Reply and Closing Briefs in Docket No. UE 173.

Q. PLEASE ELABORATE ON THE COMMISSION'S UNUSUAL EVENT STANDARD.

A. A fundamental issue in this docket is the amount of risk reduction, or conversely earnings stability, that is reasonable to achieve through implementation of a PCA mechanism. Staff has consistently argued in recent cases that PCA mechanisms should be used to protect the company from extreme fluctuations in NVPC. Staff has recommended using a deadband to exclude a reasonable range of normal variation from triggering the PCA mechanism. *See* Staff Testimony in Docket No. UE 137, Staff Closing Comments in Docket No. UM 1071, Staff Testimony in Docket No. UE 165, and Staff Testimony in Docket No. UE 173.

In Order 05-1261, the Commission indicated that the long-term operation of a PCA mechanism allows offsetting events to be reflected in customer rates and, therefore, provides an opportunity to use a more inclusive recovery standard (i.e., a narrower deadband) in a PCA mechanism than it would allow with a one-time deferral mechanism. *See* Order 05-1261 at 9-10. The Commission concluded that a hydro-only PCA mechanism should be used to protect the company from unusual variation in hydro-related power costs.

Q. DOES PGE'S PROPOSED ANNUAL VARIANCE MECHANISM SATISFY THE UNUSUAL EVENT STANDARD?

A. No. PGE's Annual Variance mechanism lacks a deadband. PGE’s Annual Variance mechanism would shift nearly all of PGE's power cost risk to customers. PGE has historically borne power cost risk and should retain a significant portion of this risk.

Q. DOES PGE INDICATE ITS REASONS FOR NOT INCLUDING A DEADBAND IN ITS ANNUAL VARIANCE MECHANISM?

A. Yes. PGE provides four reasons for not including a deadband in its Annual Variance mechanism. PGE did not include a deadband because:

1. The Public Utility Commission of Oregon has never used a deadband in an indefinite automatic adjustment mechanism;
2. A deadband interferes with the risk allocation of the forced outage rate methodology;
3. A deadband suggests that a utility's earnings opportunity must be subject to variance in costs over which the utility has little or no control; and
4. A deadband is not necessary to prevent undue rate volatility.

See PGE/400, Lesh – Niman/42-43.

Q. IS PGE'S FIRST REASON FOR NOT INCLUDING A DEADBAND IN ITS ANNUAL VARIANCE MECHANISM PERSUASIVE?

A. No. The lack of precedent for a deadband in an indefinite automatic adjustment mechanism is not a credible objection. In Docket No. UE 137, PGE included a deadband of plus and minus $22.4 million in its proposal for an indefinite PCA mechanism. PGE identified this deadband as the "biggest difference" between its proposed mechanism and the mechanism PGE had in effect from 1979 to 1987. At that time, PGE argued:

> The significant deadband included in this proposal ensures that the mechanism only captures major shifts in cost and revenues.

See UE 137, PGE/100, Dahlgren/1-2.

Q. IS PGE'S SECOND REASON FOR NOT INCLUDING A DEADBAND PERSUASIVE?

A. No. Although PGE states that the traditional four-year forced outage rate methodology used in general rate cases represents a bargain between PGE and its customers on the allocation of forced outage risk (*See* PGE/400, Lesh – Niman/6), no such bargain explicitly or implicitly exists. The purported bargain is that PGE experiences the benefits and costs of variability in plant availability as it occurs and customers receive the benefits and costs over the following four-year period. *See* PGE/400, Lesh – Niman/20. An implicit bargain would presuppose agreement on the filing of annual rate cases or on a process to annually update NVPC. This agreement does not exist. Furthermore, as Staff indicated in its direct testimony in the RVM portion of this case, the purpose of including generating unit outage rates in power cost modeling is to normalize plant availability during a future test period. The modeling of forced outage rates is not intended to provide recovery of the replacement power costs associated with past outages. *See* Staff/100, Galbraith/8. Finally, PGE's application in Docket No. UM 1234 requesting deferral of the replacement power costs associated with a recent outage at it Boardman plant is further evidence that no such bargain exists.

Q. IS PGE'S THIRD REASON FOR NOT INCLUDING A DEADBAND PERSUASIVE?

A. No. Staff believes that the degree of company control over net power costs provides little guidance with respect to the primary allocation of power cost risk between PGE and its customers. If net power costs were largely within PGE's control, then the issue of the sharing of power cost risk between the company and its customers would never arise and the company's opportunity to earn would be largely independent of the factors that drive power costs. In other words, the question of the appropriate sharing of power cost risk presupposes a significant lack of control. On the other hand, if net power costs were completely outside of PGE's control, then the management of power cost risk would be oxymoronic and the company could improve earnings by eliminating risk management expense. The point is that although PGE has little control over some of the factors that drive variation in net power costs, the company does have considerable ability to manage its power costs. PGE's lack of control argument does not justify shifting nearly all power cost risk to customers. The degree of company control over net power costs should be a secondary consideration used to fine-tune the size of the deadband and not as a reason to eliminate its use altogether. *See* Staff Reply Brief in Docket No. UE 173 at 9-11.

Q. IS PGE'S FOURTH REASON FOR NOT INCLUDING A DEADBAND PERSUASIVE?

A. No. The argument that a deadband is not needed to prevent undue rate volatility misses the point of a deadband altogether. The purpose of a deadband is to prevent normal variation in power costs from triggering the mechanism, not to prevent undue rate volatility.

Q. SHOULD THE COMMISSION REJECT PGE'S ANNUAL VARIANCE MECHANSIM?

A. Yes. PGE's proposed Annual Variance mechanism fails to satisfy the unusual event standard.

Q. IS PGE'S JUSTIFICATION OF ITS PROPOSED ANNUAL UPDATE MECHANISM PERSUASIVE?

A. No. PGE indicates that its advance power and natural gas purchasing is the primary driver of the year-to-year change in its annual NVPC. PGE's advance purchasing strategy consists of adding (or layering in) small quantities of purchased power and natural gas to its portfolio over a 12 to 24 month timeframe. This layering strategy has the intended effect of smoothing PGE's purchased power and natural gas expense over time. In other words, although the forward prices of power and natural gas are market-driven, PGE's advance purchasing strategy effectively mitigates (or averages) much of the price volatility in these markets. The following table shows the average variable cost of PGE's natural gas resources and power contracts in each of the last four RVM cases.

Table 1. Average Variable Cost of PGE's Natural Gas Resources and Power Contracts in Recent RVM Cases (in $/MWh).

	2003	**2004**	**2005**	**2006**
Natural Gas Resources	38.30	40.90	37.60	50.60
Power Purchases	38.40	42.80	46.10	52.60

See PGE/400, Lesh – Niman/28. The average variable cost of PGE's natural gas resources was relatively stable across the 2003 through 2005 RVM cases. The average cost of purchased power exhibited a gradual upward trend in the 2003 through 2006 RVM cases. Neither of these time series exhibits the highly dynamic year-to-year change that would necessitate an Annual Update mechanism. These patterns of variation can be easily handled by a power cost framework that includes a retrospective automatic adjustment clause and periodic general rate cases.

Q. PGE PROPOSES TO LIMIT THE LIST OF POWER COST COMPONENTS THAT WOULD BE INCLUDED IN THE ANNUAL UPDATE. IS IT REASONABLE TO CONCLUDE THAT THIS LIMITATION WILL REDUCE THE AMOUNT OF CONTROVERSY ASSOCIATED WITH THE ANNUAL UPDATE PROCESS?

A. Yes, somewhat. However, the list of MONET inputs that would be updated each year includes: physical and financial contracts for power and natural gas, generating unit forced outage rates and planned outage days, and forward price curves for power and natural gas. This list includes some of the most hotly contested issues in recent RVM cases.

Q. SHOULD THE COMMISSION REJECT PGE'S ANNUAL UPDATE MECHANSIM?

A. Yes. Staff is not convinced that the benefits of a prospective automatic adjustment clause outweigh its regulatory burdens.

Staff's Proposed PCA Mechanism

Q. PLEASE SUMMARIZE STAFF'S PROPOSED PCA MECHANISM.

A. Staff recommends a long-term retrospective PCA mechanism that would:

1. Track the difference between actual unit NVPC and the unit NVPC reflected in rates;
2. Determine the annual variance amount by multiplying the difference between unit NVPC by the normalized loads reflected in rates;
3. Use a power cost deadband equal to plus and minus 150 basis points of ROE to exclude normal variation from triggering the mechanism;
4. Place ninety percent of all amounts exceeding the power cost deadband in a balancing account for later offset or amortization;
5. Use an earnings test with a deadband equal to plus and minus 100 basis points of ROE to override any surcharges (surcredits) when the company's earnings are above (below) the bottom (top) of a reasonable range; and
6. Apply any surcharges or surcredits to customers that were charged cost-of-service rates during the PCA year.

Q. WHY DOES STAFF RECOMMEND DETERMINING THE ANNUAL VARIANCE BY TRACKING THE DIFFERENCE BETWEEN ACTUAL UNIT NVPC AND THE UNIT NVPC REFLECTED IN RATES AND THEN MULTIPLING THIS DIFFERENCE BY THE NORMALIZED LOADS USED TO SET COST-OF-SERVICE RATES?

A. This proposed tracking formula maintains the traditional allocation of load risk. PGE's investors currently bear the risk that reduced loads can result in less than full fixed cost coverage. Investors also benefit from greater than full fixed cost coverage when loads are above those reflected in rates. This formula accounts for the offsetting impacts of load variation on fixed cost coverage and NVPC. With increased load, greater than full recovery of fixed costs mitigates or offsets the additional power costs incurred to meet the additional load. With decreased load, the savings in power costs mitigates or offsets the less than full recovery of fixed costs.

Q. WHY DOES STAFF RECOMMEND A SYMMETRIC POWER COST DEADBAND EQUAL TO 150 BASIS POINTS OF ROE?

A. In previous testimony, Staff recommended the use of a symmetric deadband equal to 250 basis points of ROE. Staff recommends a narrower deadband in this docket for two reasons. First, staff's previous deadband recommendations were largely based on Commission decisions in recent deferred accounting dockets. The long-term operation of the proposed PCA mechanism provides an opportunity to use a narrower deadband than the one staff recommends for use in one-time deferral mechanisms. Second, staff's previous deadband recommendations were premised on the continuation of an annual power cost update. Staff no longer supports an annual power cost update. Since the annual power cost update provided PGE with some risk mitigation, staff believes a somewhat narrower PCA deadband is appropriate.

Q. WHY DOES STAFF RECOMMEND DEFERRAL OF NINETY PERCENT OF ALL AMOUNTS EXCEEDING THE DEADBAND?

A. Staff recommends amounts falling outside the deadband be shared ninety percent to customers and ten percent to PGE. Keeping a small percentage of NVPC risk with the company aligns the company and customer interests to minimize NVPC.

Q. WHY DOES STAFF RECOMMEND AN EARNINGS TEST WITH A SYMMETRIC DEADBAND EQUAL TO 100 BASIS POINTS OF ROE?

A. The Commission developed this earnings test in Order 05-1261 to prevent, or override, supplemental recovery of excess power costs through a PCA mechanism when the utility's earnings are reasonable. *See* Order 05-1261 at 9-10. The purpose of the earnings test deadband is to override any surcharges when the company's earnings are above the bottom of a reasonable range. The earnings test deadband also overrides any surcredits when the company's earnings are below the top of a reasonable range. Staff recommends the use of an earnings test deadband to prevent unreasonable recovery or refund. *See* Staff Reply and Closing Briefs in Docket No. UE 173.

Q. PGE ARGUES THAT THE COMMISSION'S UE 165 EARNINGS TEST WOULD SYSTEMATICALLY AND NEGATIVELY INTERFERE WITH A UTILITY'S RISK PROFILE AND ENTIRE COST STRUCTURE AND CHARACTERIZES THE TEST AS A PENALTY RATHER THAN A MEANS OF ASSURING REASONABLE RATES. *SEE* PGE/400, LESH – NIMAN/47-50. ARE THESE ARGUMENTS AND CHARACTERIZATIONS CREDIBLE?

A. No. Early in its testimony on its proposed power cost framework the company states:

> [The general rate case] is the proceeding in which the Commission can best address the alignment of risk allocation and cost of capital and this is why PGE is proposing a comprehensive regulatory framework for power costs in this filing.

See PGE/400, Lesh – Niman/8. Much later in its testimony the company states:

> …this unprecedented version of an earnings test would systematically and negatively interfere with the other risk allocations already made to the utility by the overall regulatory framework.

See PGE/400, Lesh – Niman/50. It is inconsistent to argue that risk allocations have already been made to the utility when the alignment of risk allocation and cost of capital, and the comprehensive regulatory framework for power costs, are being determined in this proceeding.

Q. WHY DOES STAFF RECOMMEND APPLYING THE PCA RATE TO ALL COST-OF-SERVICE CUSTOMERS WHILE EXCLUDING ALL DIRECT ACCESS AND MARKET BASED RATE CUSTOMERS?

A. Direct access provides non-residential customers the potential to obtain a fixed energy price from an ESS. Applying the PCA rate to direct access customers eliminates the potential for a fixed rate. Market-based rate options provide non-residential customers the ability to obtain market-indexed rates from the utility. Applying the PCA rate to these customers eliminates this possibility. The ability of the customer to disconnect their annual energy expense from regulated cost-of-service ratemaking is the primary benefit of these options. Applying a PCA adjustment rate to the programs eliminates the benefit.

Q. DOES STAFF'S PCA PROPOSAL SATISFY THE COMMISSIONS DESIGN STANDARDS?

A. Staff's proposed PCA mechanism satisfies three of the Commission's four design criteria. First, staff's proposed PCA mechanism is a long-term mechanism. Second, the proposed mechanism includes a power cost deadband that excludes normal variation from triggering the mechanism and limits recovery to unusual events. Third, the mechanism also includes an earnings test deadband that overrides supplemental recovery if the utility's earnings are reasonable. It is unclear whether the mechanism satisfies the Commission's fourth criteria, that it be revenue neutral over time.

Q. DOES STAFF CONTINUE TO RECOMMEND THAT PGE PURSUE EXPECTED VALUE POWER COST MODELING?

A. Yes. Staff recommends expected value power cost modeling for two reasons. First, expected value power cost modeling can provide for a more realistic simulation of PGE's system operations. It can provide a realistic representation of the variability, and any interactions, associated with retail loads, natural gas and electricity market prices, hydroelectric generation, and thermal unit availability. Second, expected value power cost modeling provides a distribution of NVPC that can be used to design a PCA mechanism that does not bias the overall expected level of power cost recovery (i.e., is revenue neutral over time). Essentially, expected value power cost modeling takes advantage of information and relationships currently not incorporated in PGE's power cost modeling. This information will improve estimation of NVPC and assessment of NVPC risk.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 180/UE 181/UE 184
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Direct Testimony

August 9, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Steve W Chriss. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I am employed by the Public Utility Commission of Oregon (OPUC or the Commission) as a Senior Utility Analyst in the Electric and Natural Gas Division.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. Exhibit Staff/901 is my Witness Qualification Statement. I have previously testified before the Commission as staff's lead witness in UX 29 and in a supporting role in UE 179 and all three phases of UM 1129.

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/902, consisting of two pages, and Exhibit Staff/903, consisting of five pages.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I address rate spread issues, including PGE's use of the Customer Impact Offset (CIO) to mitigate the rate impacts for several rate schedules.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. Relationship of Marginal Costs to Rates

II. Changes in Rate Schedules

III. Rate Implications of Revenue Requirement Increases

IV. The Customer Impact Offset (CIO) and Revenue Requirement Increase Implications

V. Phasing Out the CIO

Q. PLEASE PROVIDE A SUMMARY OF STAFF'S PROPOSED NET RATE CHANGES FOR EACH RATE SCHEDULE.

A. Table A shows the net rate changes for each rate schedule using staff's revenue requirement and CIO proposals. Table B shows the incremental rate changes after the inclusion of Port Westward in rates.

Table A. Estimated Rate Impacts of Staff's Proposed Revenue Requirement Increase of $20 Million, January 2007 (Excludes Port Westward).

Schedule	No.	Net Rate Change ($)	Net Rate Change (%)
Residential	7	2,492,024	0.39
Outdoor Area Lighting	15	26,818	0.65
General Service < 30 kW	32	1,128,594	0.87
Optional Time-of-Day GS > 30 kW	38	142,527	1.57
Irrigation and Drain. Pump. < 30 kW	47	32,212	1.91
Irrigation and Drain. Pump. > 30 kW	49	68,631	1.86
General Service > 30 kW			
Secondary	83-S	2,015,242	0.54
Primary	83-P	268,912	1.43
Schedule 89 > 1 MW			
Secondary	89-S	(164,503)	(0.35)
Primary	89-P	365,886	0.24
Transmission	89-T	384,518	0.52
Street & Highway Lighting	91	264,313	1.81
Traffic Signals	92	6,316	1.60
Recreational Field Lighting	93	1,270	1.58
Overall Net Increase		**7,042,887**	**0.48**
Source: Staff/903, Chriss/1			

Table B. Estimated Rate Impacts of the Addition of Port Westward to Rates, Initial Revenue Requirement Increase of $20 Million.

Schedule	No.	Net Increment ($)	Net Increment (%)
Residential	7	15,939,950	2.50
Outdoor Area Lighting	15	46,886	1.13
General Service < 30 kW	32	3,160,696	2.42
Optional Time-of-Day GS > 30 kW	38	214,020	2.33
Irrigation and Drain. Pump. < 30 kW	47	43,894	2.56
Irrigation and Drain. Pump. > 30 kW	49	127,691	3.39
General Service > 30 kW			
Secondary	83-S	10,958,512	2.92
Primary	83-P	582,966	3.06
Schedule 89 > 1 MW			
Secondary	89-S	1,353,459	2.93
Primary	89-P	4,758,876	3.17
Transmission	89-T	2,548,284	3.40
Street & Highway Lighting	91	194,295	1.31
Traffic Signals	92	11,798	2.94
Recreational Field Lighting	93	1,158	1.42
Overall Net Increase		**40,000,000**	**2.72**

Source: Staff/903, Chriss/1

I. Relationship of Marginal Costs to Rates

Q. PLEASE DEFINE "RECONCILIATION."

A. Reconciliation is the process of comparing marginal cost to target revenues for different customer classes. Historically, reconciliation has been performed in rate spread decisions to allocate changes in overall revenue requirement to move different customer classes closer to recovering the same share of marginal cost. *See* Appendix B of Order 98-374.

Q. ON WHAT BASIS SHOULD RECONCILIATION BE PERFORMED?

A. Reconciliation should be performed on a functionalized basis. For example, comparisons across rate schedules should be made at the level of generation, transmission, distribution, and billing marginal costs and target revenues. This methodology is consistent with Commission Order 98-374.

Q. ARE PGE'S COSTS RECONCILED IN A MANNER CONSISTENT WITH ORDER 98-374?

A. Yes.

II. Changes in Rate Schedules

Q. WHAT COMPARATOR DOES PGE USE TO DEMONSTRATE ESTIMATED RATE IMPACTS? *SEE* PGE/1300, KUNS-CODY/4, TABLE 1.

A. PGE uses estimates of prospective 2007 RVM prices as its comparator for the proposed rates in this docket. PGE claims that this measures the "true changes" resulting from the rate case. *See* PGE/1300, Kuns-Cody/4, Line 4.

Q. IS THE RVM THE APPROPRIATE COMPARATOR?

A. No. PGE's use of the RVM as the comparator is misleading; the increases shown are not necessarily wrong, as they represent the increase over what customers *would* pay were the RVM to take effect in January 2007, but they do not reflect the real increase customers *will* pay from December 2006 to January 2007. This is because the analysis ignores any increase from the rates in December 2006 to the 2007 RVM rates.

Q. WHAT IS THE INCREASE THAT CUSTOMERS WILL PAY FROM DECEMBER 2006 TO JANUARY 2007?

A. The increase that customers will pay is the difference between the actual rates in December 2006 and the proposed rates in January 2007. As such, it is appropriate to use PGE's current tariff rates, updated for any changes that will occur between now and December 31, 2006.

Q. PLEASE PROVIDE AN EXAMPLE OF THE CHANGE FROM THE RATES IN DECEMBER 2006 TO THE PROPOSED JANUARY 2007 RATES.

A. Staff/902, Chriss/1 shows the changes in rates for Schedule 7 residential customers from the rates in December 2006 to PGE's proposed rates in

January 2007. As the exhibit shows, instead of PGE's representation of percentage changes from 0.97% to 3.50%, the changes customers will see range from 1.34% to 8.30%. *See* Staff/902, Chriss/1 and PGE/1303, Kuns-Cody/4.

Q. DOES YOUR CALCULATION ASSUME A SCHEDULE 102 RATE CHANGE ON OCTOBER 1, 2006?

A. Yes. The bill comparison also includes the Low Income Charge and Public Purpose Charge in order to be directly comparable to PGE's exhibit.

Q. ARE THERE ANY OTHER CALCULATION ISSUES?

A. Yes. PGE does not include rates for Schedules 125 and 126 in its filing. *See* PGE/1302, Kuns-Cody/92 and PGE/1302, Kuns-Cody/96.

Q. HOW SHOULD THE CHANGE IN RATES UPON THE INCLUSION OF PORT WESTWARD BE REPRESENTED?

A. The change in rates should be represented as the change from rates in February 2007 to those in March 2007. PGE correctly represents this change in PGE/1303.

Q. ARE CHANGES IN OTHER RATE SCHEDULES REPRESENTED IN A SIMILAR MANNER?

A. Yes. See PGE/1303, Kuns-Cody/3-13.

Q. GIVEN BOTH RATE CHANGES WHAT IS THE TOTAL BILL IMPACT BETWEEN DECEMBER 2006 AND MARCH 2007 FOR RESIDENTIAL SCHEDULE 7 CUSTOMERS UNDER PGE'S FILINGS?

A. The total percentage change in residential bills ranges from two percent to just over eleven percent. *See* Staff/902, Chriss/2.

Discussion of Specific Schedules

Schedule 7

Q. DOES YOUR ANALYSIS SHOW THAT PGE'S SCHEDULE 7 BASIC CHARGE IS COMPARABLE TO OTHER UTILITIES?

A. No. An analysis of investor-owned electric utilities and large municipally-owned electric utilities operating in the Pacific Northwest shows that PGE has the highest basic charge for residential customers in the comparator group. See Table II-1.

Table II-1. Comparison of Basic Charges.

Company	Jurisdiction	Schedule	Basic Charge
Avista	Washington	1	$5.50
	Idaho	1	$4.00
Clark County PUD	Washington		$6.40
EWEB	Oregon	R6	$6.50
Idaho Power	Oregon	1	$5.25
	Idaho	1	$4.00
PacifiCorp	Oregon	4	$7.00
Puget Sound Energy	Washington	7	$5.75
Seattle City Light	Washington	RSS/RSC	$3.00 (est.)[1]
PGE (current and proposed)	Oregon	7	$10.00

Q. SHOULD PGE BE REQUIRED TO REDUCE ITS BASIC CHARGE?

A. No. Though high, the charge is still below marginal cost. Additionally, all customers would not necessarily be better off because the company will still recover those monies. Reducing the basic charge would cause a shift of costs to the distribution charge, which PGE uses as a catch-all charge.

[1] Rate is 9.71 cents/day.

Q. HOW IS THE SCHEDULE 7 DISTRIBUTION CHARGE CALCULATED?

A. The distribution charge contains the allocated distribution costs as well as serving as a catch-all charge for the leftover costs not recovered by the basic charge. Additionally, the distribution charge contains franchise fees and Trojan costs. Finally, the distribution cost contains a CIO adder of 0.20 mills/kWh. *See* PGE/1300, Kuns-Cody/9.

Q. IS THE CIO ADDER IN SCHEDULE 7 THE SAME AS THE ADDER IN OTHER SCHEDULES THAT PAY INTO THE MECHANISM?

A. Yes. All schedules that pay into the CIO mechanism are charged the same per kilowatt-hour adder.

Q. IS PGE PROPOSING TO CHANGE THE STRUCTURE OF THE ENERGY CHARGE IN SCHEDULE 7?

A. Yes. PGE has proposed a flat energy charge for all kilowatt-hours sold under Schedule 7. PGE's current energy charge features a declining block rate structure in Schedule 7 itself, but once the supplemental rate schedules are figured in, the energy rates have an inverted-block structure.

Q. WHAT IS AN INVERTED-BLOCK STRUCTURE?

A. Simply put, an inverted-block structure is when energy consumed at lower levels costs less on a per kilowatt-hour basis than energy consumed at higher levels. These levels, or "blocks," are set on customer usage characteristics selected by the utility. For PGE, the lower block is monthly consumption of 250 kWh or less and the higher block is monthly consumption of more than 250 kWh.

An example of how the inverted-block structure works is a utility charges 4 c/kWh for the first 250 kWh and 6 c/kWh for all kWh above 250 kWh consumed in a month. Customer X consumes 300 kWh in a month and is billed $13 for the energy portion of their bill. This works out to (0.04 x 250) + (0.06 x 50) = $13.

Q. WHY IS AN INVERTED-BLOCK STRUCTURE USEFUL FOR PGE'S RESIDENTIAL CUSTOMERS?

A. The inverted-block structure, both current and proposed, is useful for two reasons. First, it confers the benefits of the region's hydro power on lower use customers, as the inverted-block structure is created by the Regional Power Act Exchange Credit (RPA credit) and the credit is higher in the lower block. *See* PGE/1302, Kuns-Cody/84. Second, it provides a conservation incentive because higher consumption costs more on a per unit basis than lower consumption.

Q. AFTER SUPPLEMENTAL RATE SCHEDULES ARE FIGURED INTO RESIDENTIAL RATES, WHAT RATE STRUCTURE DO RESIDENTIAL CUSTOMERS FACE?

A. Rates would effectively remain in an inverted-block due to the Regional Power Act Exchange Credit (RPA credit), which is applied at a rate of $2.294 c/kWh for the first 250 kWh and $0.763 c/kWh over 250 kWh.

Q. WHAT ARE THE RESULTING ENERGY PRICES, BOTH CURRENT AND ASSUMING THE PROPOSED RATE INCREASES?

A. The resulting energy prices are shown in Table II-2.

Table II-2. Energy Prices (c/kWh): Current, UE 180 Proposed, and Port Westward Proposed.

	Current	UE 180 Proposed	Port Westward Proposed
<= 250 kWh	3.735	3.371	3.587
> 250 kWh	4.985	4.902	5.118

Schedule 83

Q. PGE'S TRANSMISSION AND RELATED SERVICES CHARGE FOR CUSTOMERS ON SCHEDULE 89 IS BASED ON A CUSTOMER'S MONTHLY ON-PEAK DEMAND. IS THE COMPANY'S TRANSMISSION RATE FOR SCHEDULE 83 SIMILARLY BASED?

A. No. The transmission and related services charge for Schedule 83 is charged per kW of monthly demand, regardless of when that peak occurs. As a result, customers on Schedule 83 who experience their maximum demand during off-peak hours may see their transmission charge set at a time when their maximum demand has no impact on the costs of sizing the transmission system.

Q. WHAT IS STAFF'S PROPOSAL?

A. PGE should commit to basing the transmission and related services charge on kW of monthly on-peak demand if all Schedule 83 customers have the appropriate metering installed prior to their next rate case.

III. Rate Implications of Revenue Requirement Increases

Q. PLEASE DESCRIBE YOUR ANALYSIS OF THE ESTIMATED RATE IMPLICATIONS OF INCREASES TO THE REVENUE REQUIREMENT.

A. I analyzed the estimated net rate implications, including supplements, of increases to the revenue requirement at four levels of increase: $40 million; $60 million; $80 million; and $100 million. The fourth level of increase, $100 million, is approximately the increase requested by PGE in its initial filing.

Q. CAN THIS ANALYSIS BE USED TO ANALYZE THE IMPACTS OF PORT WESTWARD?

A. No. A separate analysis is performed to analyze the incremental change in net rates after the inclusion of Port Westward in rates. The separate analysis is required because Port Westward monies are not included in the CIO mechanism. Additionally, the calculated percentage increase also depends on the results of the initial revenue requirement increase analysis.

Q. WHAT IS THE INTENT OF THIS ANALYSIS?

A. The intent of this analysis is to provide the Commission with points of reference along the scale of potential revenue requirement increases. However, analysis of these price levels does not constitute an endorsement of any revenue requirement level other than staff’s recommended revenue requirement.

Revenue Requirement Increase of $40 Million

Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF A REVENUE REQUIREMENT INCREASE OF $40 MILLION?

A. The overall estimated net impact of a $40 million increase is an increase of 1.85 percent. The changes in individual rate schedules range from 0.10 percent to 4.89 percent. *See* Table III-1.

Q. DO THESE ESTIMATES TAKE THE CIO INTO ACCOUNT?

A. Yes. These estimates are the net rate increases including CIO. Because of the methodology PGE uses to calculate base rates, it is impossible to estimate net rates without including the CIO. I will discuss the CIO and dollars transferred between classes later in my testimony.

Table III-1. Estimated Rate Impacts of a Revenue Requirement Increase of $40 Million.

Schedule	No.	Net Rate Increase ($)	Net Rate Increase (%)
Residential	7	11,089,281	1.75
Outdoor Area Lighting	15	78,777	1.91
General Service < 30 kW	32	3,429,563	2.65
Optional Time-of-Day GS > 30 kW	38	353,842	3.91
Irrigation and Drain. Pump. < 30 kW	47	81,616	4.85
Irrigation and Drain. Pump. > 30 kW	49	180,751	4.89
General Service > 30 kW			
Secondary	83-S	7,056,092	1.89
Primary	83-P	681,137	3.63
Schedule 89 > 1 MW			
Secondary	89-S	44,782	0.10
Primary	89-P	1,929,019	1.29
Transmission	89-T	1,403,812	1.89
Street & Highway Lighting	91	639,147	4.37
Traffic Signals	92	16,373	4.14
Recreational Field Lighting	93	3,319	4.14
Overall Net Increase		**27,026,374**	**1.85**

Source: Staff/903, Chriss/2

Q. WHAT IS THE INCREMENTAL NET RATE IMPACT OF THE ADDITION OF PORT WESTWARD?

A. The overall estimated impact of the addition of Port Westward to the previous revenue requirement increase of $40 million is 2.68 percent. The changes in individual rate schedules range from 1.11 percent to 3.36 percent. *See* Table III-2.

Q. WHAT VALUE IS USED FOR THE PORT WESTWARD INCREMENT?

A. This analysis uses staff's proposed increment of $40 million.

Table III-2. Estimated Rate Impacts of the Addition of Port Westward to Rates, Initial Revenue Requirement Increase of $40 Million.

Schedule	No.	Net Increment ($)	Net Increment (%)
Residential	7	15,939,950	2.47
Outdoor Area Lighting	15	46,886	1.11
General Service < 30 kW	32	3,160,696	2.38
Optional Time-of-Day GS > 30 kW	38	214,020	2.27
Irrigation and Drain. Pump. < 30 kW	47	43,894	2.49
Irrigation and Drain. Pump. > 30 kW	49	127,691	3.30
General Service > 30 kW			
Secondary	83-S	10,958,512	2.88
Primary	83-P	582,966	3.00
Schedule 89 > 1 MW			
Secondary	89-S	1,353,459	2.92
Primary	89-P	4,758,876	3.14
Transmission	89-T	2,548,284	3.36
Street & Highway Lighting	91	194,295	1.27
Traffic Signals	92	11,798	2.87
Recreational Field Lighting	93	1,158	1.39
Overall Net Increase		**40,000,000**	**2.68**
Source: Staff/903, Chriss/2			

Revenue Requirement Increase of $60 Million

Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF A REVENUE REQUIREMENT INCREASE OF $60 MILLION?

A. The overall estimated net impact of a $60 million increase is an increase of 3.21 percent. The changes in individual rate schedules range from 0.55 percent to 7.93 percent. *See* Table III-3.

Table III-3. Estimated Rate Impacts of a Revenue Requirement Increase of $60 Million.

Schedule	No.	Net Rate Increase ($)	Net Rate Increase (%)
Residential	7	19,686,539	3.10
Outdoor Area Lighting	15	130,737	3.16
General Service < 30 kW	32	5,730,532	4.42
Optional Time-of-Day GS > 30 kW	38	565,158	6.24
Irrigation and Drain. Pump. < 30 kW	47	131,020	7.79
Irrigation and Drain. Pump. > 30 kW	49	292,871	7.93
General Service > 30 kW			
Secondary	83-S	12,096,942	3.24
Primary	83-P	1,093,363	5.83
Schedule 89 > 1 MW			
Secondary	89-S	254,066	0.55
Primary	89-P	3,492,152	2.33
Transmission	89-T	2,423,105	3.25
Street & Highway Lighting	91	1,014,959	6.94
Traffic Signals	92	26,490	6.71
Recreational Field Lighting	93	5,374	6.70
Overall Net Increase		**47,010,904**	**3.21**
Source: Staff/903, Chriss/3			

Q. **WHAT IS THE INCREMENTAL NET RATE IMPACT OF THE ADDITION OF PORT WESTWARD?**

A. The overall estimated impact of the addition of Port Westward to the previous revenue requirement increase of $60 million is 2.65 percent. The changes in individual rate schedules range from 1.10 percent to 3.31 percent. *See* Table III-4.

Table III-4. Estimated Rate Impacts of the Addition of Port Westward to Rates, Initial Revenue Requirement Increase of $60 Million.

Schedule	No.	Net Increment ($)	Net Increment (%)
Residential	7	15,939,950	2.43
Outdoor Area Lighting	15	46,886	1.10
General Service < 30 kW	32	3,160,696	2.33
Optional Time-of-Day GS > 30 kW	38	214,020	2.22
Irrigation and Drain. Pump. < 30 kW	47	43,894	2.42
Irrigation and Drain. Pump. > 30 kW	49	127,691	3.20
General Service > 30 kW			
Secondary	83-S	10,958,512	2.84
Primary	83-P	582,966	2.94
Schedule 89 > 1 MW			
Secondary	89-S	1,353,459	2.90
Primary	89-P	4,758,876	3.11
Transmission	89-T	2,548,284	3.31
Street & Highway Lighting	91	194,295	1.24
Traffic Signals	92	11,798	2.80
Recreational Field Lighting	93	1,158	1.35
Overall Net Increase		**40,000,000**	**2.65**
Source: Staff/903, Chriss/3			

Revenue Requirement Increase of $80 Million

Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF A REVENUE REQUIREMENT INCREASE OF $80 MILLION?

A. The overall estimated net impact of an $80 million increase is an increase of 4.58 percent. The changes in individual rate schedules range from 1.00 percent to 10.98 percent. *See* Table III-5.

Table III-5. Estimated Rate Impacts of a Revenue Requirement Increase of $80 Million.

Schedule	No.	Net Rate Increase ($)	Net Rate Increase (%)
Residential	7	28,283,797	4.45
Outdoor Area Lighting	15	182,696	4.42
General Service < 30 kW	32	8,031,501	6.20
Optional Time-of-Day GS > 30 kW	38	776,473	8.57
Irrigation and Drain. Pump. < 30 kW	47	180,882	10.75
Irrigation and Drain. Pump. > 30 kW	49	405,671	10.98
General Service > 30 kW			
Secondary	83-S	17,137,792	4.58
Primary	83-P	1,505,589	8.03
Schedule 89 > 1 MW			
Secondary	89-S	463,351	1.00
Primary	89-P	5,055,285	3.38
Transmission	89-T	3,442,399	4.62
Street & Highway Lighting	91	1,392,728	9.53
Traffic Signals	92	36,606	9.27
Recreational Field Lighting	93	7,446	9.29
Overall Net Increase		**66,998,550**	**4.58**

Source: Staff/903, Chriss/4

Q. **WHAT IS THE INCREMENTAL NET RATE IMPACT OF THE ADDITION OF PORT WESTWARD?**

A. The overall estimated impact of the addition of Port Westward to the previous revenue requirement increase of $80 million is 2.61 percent. The changes in individual rate schedules range from 1.09 percent to 3.27 percent. *See* Table III-6.

Table III-6. Estimated Rate Impacts of the Addition of Port Westward to Rates, Initial Revenue Requirement Increase of $80 Million.

Schedule	No.	Net Increment ($)	Net Increment (%)
Residential	7	15,939,950	2.40
Outdoor Area Lighting	15	46,886	1.09
General Service < 30 kW	32	3,160,696	2.30
Optional Time-of-Day GS > 30 kW	38	214,020	2.18
Irrigation and Drain. Pump. < 30 kW	47	43,894	2.36
Irrigation and Drain. Pump. > 30 kW	49	127,691	3.11
General Service > 30 kW			
Secondary	83-S	10,958,512	2.80
Primary	83-P	582,966	2.88
Schedule 89 > 1 MW			
Secondary	89-S	1,353,459	2.89
Primary	89-P	4,758,876	3.07
Transmission	89-T	2,548,284	3.27
Street & Highway Lighting	91	194,295	1.21
Traffic Signals	92	11,798	2.73
Recreational Field Lighting	93	1,158	1.32
Overall Net Increase		**40,000,000**	**2.61**
Source: Staff/903, Chriss/4			

Revenue Requirement Increase of $100 Million

Q. WHAT ARE THE ESTIMATED RATE IMPACTS OF A REVENUE REQUIREMENT INCREASE OF $100 MILLION?

A. The overall estimated net impact of a $100 million increase is an increase of 5.95 percent. The changes in individual rate schedules range from 1.46 percent to 14.02 percent. *See* Table III-7.

Table III-7. Estimated Rate Impacts of a Revenue Requirement Increase of $100 Million.

Schedule	No.	Net Rates ($)	Net Rates (%)
Residential	7	36,956,299	5.82
Outdoor Area Lighting	15	234,890	5.68
General Service < 30 kW	32	10,347,501	7.98
Optional Time-of-Day GS > 30 kW	38	987,789	10.91
Irrigation and Drain. Pump. < 30 kW	47	230,286	13.69
Irrigation and Drain. Pump. > 30 kW	49	517,791	14.02
General Service > 30 kW			
Secondary	83-S	22,232,670	5.95
Primary	83-P	1,920,800	10.24
Schedule 89 > 1 MW			
Secondary	89-S	679,310	1.46
Primary	89-P	6,643,361	4.44
Transmission	89-T	4,475,275	6.01
Street & Highway Lighting	91	1,768,540	12.10
Traffic Signals	92	46,723	11.83
Recreational Field Lighting	93	9,495	11.84
Overall Net Increase		**87,176,077**	**5.96**

Source: Staff/903, Chriss/5

Q. **WHAT IS THE INCREMENTAL NET RATE IMPACT OF THE ADDITION OF PORT WESTWARD?**

A. The overall estimated impact of the addition of Port Westward to the previous revenue requirement increase of $100 million is 2.58 percent. The changes in individual rate schedules range from 1.07 percent to 3.23 percent. *See* Table III-8.

Table III-8. Estimated Rate Impacts of the Addition of Port Westward to Rates, Initial Revenue Requirement Increase of $100 Million.

Schedule	No.	Net Increment ($)	Net Increment (%)
Residential	7	15,939,950	2.37
Outdoor Area Lighting	15	46,886	1.07
General Service < 30 kW	32	3,160,696	2.26
Optional Time-of-Day GS > 30 kW	38	214,020	2.13
Irrigation and Drain. Pump. < 30 kW	47	43,894	2.29
Irrigation and Drain. Pump. > 30 kW	49	127,691	3.03
General Service > 30 kW			
Secondary	83-S	10,958,512	2.77
Primary	83-P	582,966	2.82
Schedule 89 > 1 MW			
Secondary	89-S	1,353,459	2.88
Primary	89-P	4,758,876	3.04
Transmission	89-T	2,548,284	3.23
Street & Highway Lighting	91	194,295	1.19
Traffic Signals	92	11,798	2.67
Recreational Field Lighting	93	1,158	1.29
Overall Net Increase		**40,000,000**	**2.58**
Source: Staff/903, Chriss/5			

IV. The Customer Impact Offset (CIO) and Revenue Requirement Increase Implications

Q. WHAT IS THE CIO DESIGNED TO DO?

A. The CIO is designed to cap individual schedule *base* rate increases that, absent the offset, would be significantly higher than the average increase. More simply, when the base rate increase for a rate schedule exceeds a capped value, the excess revenue requirement is paid via allocations to other rate schedules. Essentially, rate schedules that do not exceed the capped value subsidize those that do.

Q. WHAT CAP VALUE DOES PGE PROPOSE?

A. PGE proposes a cap for each rate schedule of 2.0 times the overall base price increase.

Q. WHAT IS THE BASIS FOR THE LEVEL OF THE CAP?

A. The cap is set arbitrarily and attempts to balance moving schedules receiving the CIO payment closer to cost of service while mitigating rate shocks. *See* PGE/1300, Kuns-Cody/21, Lines 6-23.

Q. IS THE LEVEL OF THE CAP REASONABLE?

A. Yes. However, in circumstances such as those of Schedules 47 and 49, staff believes it can be appropriate, given the level of revenue requirement, to impose an even larger increase in order to push those schedules towards cost of service.

Q. HOW DOES PGE PROPOSE TO IMPLEMENT THE CIO?

A. PGE's filing implements CIO credit on a per kilowatt-hour basis to Schedules 47, 49, 91, 92, and 93.

Q. WHICH SCHEDULES PAY IN TO THE CIO?

A. Schedules 7, 15, 32, 83, and 39 all pay a 0.20 mill/kWh surcharge.

Q. IS THE EQUAL PER KILOWATT-HOUR SURCHARGE STRUCTURE REASONABLE?

A. Yes, in part. Staff believes that if an offset is necessary, then the equal surcharge structure is the most equitable way to structure payments in to the mechanism.

Q. HOW SHOULD THE IMPLEMENTATION OF THE CIO BE CHANGED?

A. Schedules 91 and 92, for which "funds for payment of Electricity generally are provided through taxation and property assessment,"[2] should be removed from the CIO mechanism. As a result, these schedules would be ineligible to either receive payments from the CIO mechanism or to pay into the CIO mechanism.

Q. WHY SHOULD SCHEDULES 91 AND 92 BE REMOVED FROM THE CIO?

A. PGE's electricity rates should not be used to offset the tax burden of municipalities, counties, or agencies that are PGE street lighting, highway lighting, or traffic signal customers.

For example, Salem ratepayers' payments into the CIO subsidize, in-part, street lighting in Portland, which essentially allows the City of Portland to tax Salem ratepayers through PGE rates. Additionally, these same Salem

[2] *See* PGE/1302, Kuns-Cody/69.

ratepayers could be double-taxed by the city of Salem for street lighting, as they may be paying for the full unsubsidized rates in their property taxes and also paying monies into the CIO that the City of Salem receives in rate surcredits.

It is important to consider that the taxpayers, not the municipality, county, or agency, are the ultimate customers of Schedules 91 and 92. Because the Commission cannot regulate the relationship between taxing authorities and taxpayers to ensure that the ultimate customers are correctly paying the costs to provide service, that burden should be passed to the taxing authorities. To attempt to ensure that ratepayers get what they pay for and that taxpayers pay for what they get, the Commission should remove Schedules 91 and 92 from the CIO mechanism.

Q. DOES THE REMOVAL OF THE TWO SCHEDULES REPRESENT A PHILOSOPHICAL CHANGE FROM YOUR PREVIOUS TESTIMONY?

A. Yes. I have previously testified before the Commission advocating the use of an equal offset surcharge for *all* rate schedules who do not receive an offset surcredit. *See* Staff/900, Chriss/20-22 in Docket UE 179. Further investigation of this issue has led to the refinement of my position.

Q. MUNICIPALITIES, COUNTIES, AND AGENCIES PURCHASE POWER FROM PGE UNDER OTHER RATE SCHEDULES. SHOULD THESE PURCHASES BE REMOVED FROM THE CIO MECHANISM?

A. No. Under PGE's current rate schedules in which government and non-government purchases are mixed together, it may not be feasible for the company to account for purchases by government bodies. Additionally, separating out those purchases on the same rate schedule and not applying a CIO surcredit or surcharge would violate ORS 757.310(2), which states:

> "A public utility may not charge a customer a rate or an amount for a service that is different from the rate or amount the public utility charges any other customer for a like and contemporaneous service under substantially similar circumstances."

Q. ARE ANY RATE SCHEDULES IN THE REVENUE REQUIREMENT INCREASE EXAMPLES PROVIDED IN TABLES III-1, III-3, III-5, AND III-7 SUBJECT TO THE CIO?

A. Yes. There are CIO implications at all of the levels of revenue requirement increase in Tables III-1, III-3, III-5, and III-7. Tables IV-1 through IV-4 illustrate the CIO implications for schedules with increases that exceed the cap at PGE's proposed cap of 2.0.

Table IV-1. Estimated CIO Impacts of a Revenue Requirement Increase of $40 Million, with CIO at 2.0X.

Schedule	No.	CIO ($000)	CIO Credit (c/kWh)
Small Irrigation	47	(348)	(1.518)
Large Irrigation	49	(862)	(1.269)
Street and Highway Lighting	91	(385)	(0.394)
Traffic Signals	92	(8)	(0.130)
Recreational Lighting	93	(3)	(0.515)
Overall CIO		**(1,606)**	
CIO Surcharge for Other Schedules:			**0.008**

Table IV-1. Estimated CIO Impacts of a Revenue Requirement Increase of $60 Million, with CIO at 2.0X.

Schedule	No.	CIO ($000)	CIO Credit (c/kWh)
Small Irrigation	47	(521)	(2.273)
Large Irrigation	49	(1,291)	(1.900)
Street and Highway Lighting	91	(570)	(0.583)
Traffic Signals	92	(11)	(0.191)
Recreational Lighting	93	(4)	(0.765)
Overall CIO		**(2,398)**	
CIO Surcharge for Other Schedules:			**0.012**

Table IV-1. Estimated CIO Impacts of a Revenue Requirement Increase of $80 Million, with CIO at 2.0X.

Schedule	No.	CIO ($000)	CIO Credit (c/kWh)
Small Irrigation	47	(694)	(3.026)
Large Irrigation	49	(1,719)	(2.530)
Street and Highway Lighting	91	(753)	(0.770)
Traffic Signals	92	(15)	(0.252)
Recreational Lighting	93	(6)	(1.012)
Overall CIO		**(3,186)**	
CIO Surcharge for Other Schedules:			**0.016**

Table IV-1. Estimated CIO Impacts of a Revenue Requirement Increase of $100 Million, with CIO at 2.0X (Not Including Port Westward.)

Schedule	No.	CIO ($000)	CIO Credit (c/kWh)
Small Irrigation	47	(867)	(3.781)
Large Irrigation	49	(2,148)	(3.161)
Street and Highway Lighting	91	(938)	(0.959)
Traffic Signals	92	(19)	(0.313)
Recreational Lighting	93	(7)	(1.263)
Overall CIO		**(3,978)**	
CIO Surcharge for Other Schedules:			**0.021**

VII. Phasing Out the CIO

Q. WHAT IS THE PRIMARY REASON TO PHASE OUT THE CIO?

A. The primary reason to phase out the CIO is the importance of each customer class paying its share of revenue requirements as determined by Commission policy.

Q. WHY IS IT IMPORTANT FOR EACH CUSTOMER CLASS TO PAY RATES THAT REFLECT THE COST OF SERVICE?

A. Rates based on these costs will send correct price signals to all customers. For example, PGE is proposing a 3.698 cents/kWh CIO surcredit for customers on Schedule 47. This surcredit essentially cuts the schedule's distribution rate in half. *See* PGE/1304, Kuns-Cody/5. As a result, customer consumption may differ from what it would be if prices reflected the actual cost of service. Returning all customers to paying rates that reflect the cost of service would eliminate potential over-consumption due to incorrect price signals.

Q. HOW SHOULD THE CIO BE PHASED OUT?

A. As future rate cases arise, reductions in the CIO should occur by moving base rates for schedules closer to the costs that result from the reconciliation of marginal costs and target revenues. This is staff's primary recommendation at this time, in order to provide customers advance notice of staff's position on the CIO prior to PGE's next rate case.

Q. ARE THERE ANY POTENTIAL MECHANISMS THAT COULD BE USED TO PHASE OUT THE CIO?

A. One potential mechanism is a multiyear year phase out. The first year of the mechanism would reflect the full amount of the CIO as calculated in the rate spread model. For each year following, the percent reduction in the CIO amount would be calculated by diving 100 percent by the number of years in the phase out. For example, a five year phase out would reduce the CIO amount by 20 percent of the initial CIO amount each year after the first year of the plan. Surcharges and surcredits would be calculated for each year of the mechanism.

Q. WHAT SHOULD BE CONSIDERED IN IMPLEMENTING A PHASE OUT MECHANISM?

A. The first consideration is finding an annual level of reduction in CIO monies that achieves the goal of moving CIO monies towards zero but also minimizes rate shocks to rate schedules receiving the surcredits. The second consideration is that, as cost and CIO calculations change in each rate case, so too will the mechanism calculations if PGE were to file a rate case before the phase out is complete.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 180/UE 181/UE 184
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

August 9, 2006

WITNESS QUALIFICATIONS STATEMENT

NAME:	STEVE W CHRISS
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR UTILITY ANALYST
ADDRESS:	550 CAPITOL ST. NE, SUITE 215, SALEM, OR 97310-1380
EDUCATION:	Masters of Science degree, Agricultural Economics, from Louisiana State University (2001).
	Bachelor of Science degree, Agricultural Development, from Texas A&M University (1997).
	Bachelor of Science degree, Horticulture, from Texas A&M University (1997).
EXPERIENCE:	Employed with the Public Utility Commission of Oregon (OPUC) as a Senior Utility Analyst in the Electric and Natural Gas Division. Previously employed with the OPUC as an Economist in the Economic Research and Financial Analysis Division from June, 2003 through February, 2006. Previously submitted testimony as the lead witness in Oregon docket UX 29 and as a supporting witness Oregon dockets UE 179 and UM 1129.
	Employed as an Analyst and Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based economic and regulatory consulting firm, between 2001 and 2003. Worked on regulatory and market issues in electricity, natural gas, and oil in both domestic and international markets.
	Employed by North Harris College in Houston as an adjunct microeconomics instructor from January through May 2003.

CASE: UE 180/UE 181/UE 184
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
of Direct Testimony

August 9, 2006

kWh	Current Rates (12/06)		Proposed Rates (1/07)		Percent Difference
50	$	13.89	$	14.08	1.34%
100	$	17.15	$	17.52	2.17%
200	$	23.67	$	24.42	3.14%
250	$	26.93	$	27.86	3.45%
300	$	30.84	$	32.10	4.09%
400	$	38.64	$	40.57	4.97%
500	$	46.45	$	49.04	5.56%
600	$	54.26	$	57.51	5.98%
700	$	62.07	$	65.98	6.29%
800	$	69.88	$	74.45	6.53%
900	$	77.69	$	82.91	6.73%
1,000	$	85.50	$	91.38	6.89%
1,100	$	93.30	$	99.85	7.02%
1,200	$	101.11	$	108.32	7.13%
1,300	$	108.92	$	116.79	7.23%
1,400	$	116.73	$	125.26	7.31%
1,500	$	124.54	$	133.73	7.38%
1,600	$	132.35	$	142.20	7.45%
1,700	$	140.15	$	150.67	7.50%
1,800	$	147.96	$	159.14	7.56%
2,000	$	163.58	$	176.08	7.64%
2,300	$	187.01	$	201.49	7.75%
2,750	$	222.14	$	239.60	7.86%
3,000	$	241.66	$	260.78	7.91%
3,500	$	280.71	$	303.13	7.99%
4,000	$	319.75	$	345.48	8.05%
4,500	$	358.79	$	387.82	8.09%
5,000	$	397.83	$	430.17	8.13%
7,500	$	593.04	$	641.91	8.24%
10,000	$	788.25	$	853.66	8.30%

kWh	Current Rates (12/07)	Port Westward Rates (3/07)	Percent Difference
50	$ 13.89	$ 14.20	2.22%
100	$ 17.15	$ 17.77	3.59%
200	$ 23.67	$ 24.90	5.20%
250	$ 26.93	$ 28.47	5.72%
300	$ 30.84	$ 32.83	6.46%
400	$ 38.64	$ 41.54	7.50%
500	$ 46.45	$ 50.26	8.19%
600	$ 54.26	$ 58.97	8.68%
700	$ 62.07	$ 67.68	9.04%
800	$ 69.88	$ 76.40	9.33%
900	$ 77.69	$ 85.11	9.56%
1,000	$ 85.50	$ 93.83	9.74%
1,100	$ 93.30	$ 102.54	9.90%
1,200	$ 101.11	$ 111.25	10.03%
1,300	$ 108.92	$ 119.97	10.14%
1,400	$ 116.73	$ 128.68	10.24%
1,500	$ 124.54	$ 137.39	10.32%
1,600	$ 132.35	$ 146.11	10.40%
1,700	$ 140.15	$ 154.82	10.47%
1,800	$ 147.96	$ 163.54	10.52%
2,000	$ 163.58	$ 180.96	10.63%
2,300	$ 187.01	$ 207.11	10.75%
2,750	$ 222.14	$ 246.32	10.88%
3,000	$ 241.66	$ 268.10	10.94%
3,500	$ 280.71	$ 311.67	11.03%
4,000	$ 319.75	$ 355.24	11.10%
4,500	$ 358.79	$ 398.81	11.15%
5,000	$ 397.83	$ 442.38	11.20%
7,500	$ 593.04	$ 660.22	11.33%
10,000	$ 788.25	$ 878.07	11.39%

CASE: UE 180/UE 181/UE 184
WITNESS: Steve W Chriss

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 903

Exhibits in Support of Direct Testimony

August 9, 2006

CATEGORY	Rate Schedule (1)	Present Revenues ($) Base Rates (2)	Present Revenues ($) Net Rates (3)	Proposed Base Rates (4)	PGE Filed CIO Revenues (5)	PGE Difference (6) (4) - (2) - (5)	Apply Staff Multiplier (7) (6) * (SM)	Revenues for CIO @ 2X @ Staff RR (8)	Staff Estimated Base Rates (9) (2) + (7) + (8)
Residential	7	718,962,868	635,784,749	761,181,928	1,504,884	40,714,176	8,305,958	300,977	727,569,802
Employee Discount		(770,359)	(684,662)	(817,793)					
Subtotal		718,192,508	635,100,087	760,364,135	1,504,884	40,666,742	8,296,281	300,977	726,789,766
Outdoor Area Lighting	15	4,196,109	4,133,012	4,450,894	4,699	250,086	51,019	940	4,248,068
General Service <30 kW	32	131,132,120	129,641,279	142,416,923	300,609	10,984,194	2,240,847	60,122	133,433,089
Opt. Time-of-Day G.S. >30 kW	38	9,057,369	9,056,184	10,093,196	-	1,035,827	211,316	-	9,268,684
Irrig. & Drain. Pump. < 30 kW	47	1,916,636	1,682,697	2,159,459	(847,647)	1,090,470	222,463	(174,893)	1,964,206
Irrig. & Drain. Pump. > 30 kW	49	4,340,977	3,694,522	4,890,594	(2,101,736)	2,651,352	540,893	(433,530)	4,448,341
General Service >30 kW									
Secondary	83-S	373,440,731	373,803,541	398,171,209	1,080,574	23,649,905	4,824,735	216,115	378,481,580
Primary	83-P	18,670,550	18,760,067	20,692,372	59,714	1,962,108	400,283	11,943	19,082,775
Schedule 89 > 1 MW									
Secondary	89-S	45,904,320	46,378,229	46,932,813	133,495	894,998	182,585	26,699	46,113,604
Primary	89-P	148,087,674	149,758,830	155,759,641	498,853	7,173,115	1,463,362	99,771	149,650,806
Subtransmission	89-T	73,564,085	74,460,512	78,565,798	271,644	4,730,068	964,965	54,329	74,583,379
Street & Highway Lighting	91	14,551,163	14,620,605	16,392,774	(906,662)	2,748,272	560,665	(199,524)	14,912,304
Traffic Signals	92	390,786	395,062	440,258	(17,876)	67,348	13,739	(4,039)	400,487
Recreational Field Lighting	93	79,596	80,167	89,672	(6,923)	16,999	3,466	(1,492)	81,572
TOTAL (CYCLE YEAR BASIS)		1,543,524,623	1,461,564,795	1,641,419,738		97,895,115	19,971,243		1,563,458,662
CONVERSION ADJUSTMENT		*2,222,575*	*2,104,558*	*2,363,537*		*140,963*	*28,757*		*2,251,278*
TOTAL (CALENDAR YEAR BASIS)		1,545,747,198	1,463,669,353	1,643,783,275		98,036,077	20,000,000		1,565,709,941

CATEGORY	Base Rates Jan 07 ($) (10) (9) - (2)	Base Rates Jan 07 (%) (11) (9) / (2)	PGE Total Supplementals (10)	Staff Estimated Net Rates (12) (9) + (10)	Net Rates Jan 07 ($) (13) (12) - (3)	Net Rates Jan 07 (%) (14) (12) / (3)	PGE PW Increment (15)	Apply Staff Multiplier (16) (15) * (SM2)	Staff Estimated Net Rates W/ Increment (17) (12) + (17)	Net Rate Increment March 07 ($) (18) (17) - (12)	Net Rate Increment March 07 (%) (19) (17) / (12)
Residential			(89,197,655)	638,372,147			$17,832,877				
Employee Discount							($19,589)				
Subtotal	8,597,258	1.20%	(89,197,655)	637,592,111	2,492,024	0.39%	$17,813,289	15,939,950	653,532,061	15,939,950	2.50%
Outdoor Area Lighting	51,959	1.24%	(88,237)	4,159,831	26,818	0.65%	$52,396	46,886	4,206,717	46,886	1.13%
General Service <30 kW	2,300,969	1.75%	(2,663,216)	130,769,873	1,128,594	0.87%	$3,532,156	3,160,696	133,930,569	3,160,696	2.42%
Opt. Time-of-Day G.S. >30 kW	211,316	2.33%	(69,974)	9,198,711	142,527	1.57%	$239,173	214,020	9,412,731	214,020	2.33%
Irrig. & Drain. Pump. < 30 kW	47,570	2.48%	(249,296)	1,714,910	32,212	1.91%	$49,053	43,894	1,758,804	43,894	2.56%
Irrig. & Drain. Pump. > 30 kW	107,363	2.47%	(685,187)	3,763,154	68,631	1.86%	$142,698	127,691	3,890,845	127,691	3.39%
General Service >30 kW											
Secondary	5,040,850	1.35%	(2,662,797)	375,818,783	2,015,242	0.54%	$12,246,408	10,958,512	386,777,295	10,958,512	2.92%
Primary	412,226	2.21%	(53,796)	19,028,979	268,912	1.43%	$651,479	582,966	19,611,945	582,966	3.06%
Schedule 89 > 1 MW											
Secondary	209,285	0.46%	100,122	46,213,726	(164,503)	-0.35%	$1,512,524	1,353,459	47,567,185	1,353,459	2.93%
Primary	1,563,133	1.06%	473,910	150,124,716	365,886	0.24%	$5,318,162	4,758,876	154,883,593	4,758,876	3.17%
Subtransmission	1,019,294	1.39%	261,651	74,845,030	384,518	0.52%	$2,847,771	2,548,284	77,393,314	2,548,284	3.40%
Street & Highway Lighting	361,141	2.48%	(27,386)	14,884,919	264,313	1.81%	$217,129	194,295	15,079,213	194,295	1.31%
Traffic Signals	9,701	2.48%	891	401,378	6,316	1.60%	$13,185	11,798	413,176	11,798	2.94%
Recreational Field Lighting	1,976	2.48%	(136)	81,436	1,270	1.58%	$1,294	1,158	82,594	1,158	1.42%
TOTAL (CYCLE YEAR BASIS)	19,934,040	1.29%	(184,058,762)	1,468,597,556	7,032,761	0.48%	$44,636,717	39,942,485	1,508,540,041	39,942,485	2.72%
CONVERSION ADJUSTMENT				*2,114,685*			*64,274*	*57,516*	*2,172,199*	*57,516*	
TOTAL (CALENDAR YEAR BASIS)	19,962,743	1.29%		1,470,712,240	7,042,887	0.48%	44,700,991	40,000,000	1,510,712,240	40,000,000	2.72%

PGE Increase:	$ 98,036,077
Staff Increase:	$ 20,000,000
Staff Multiplier (SM):	0.20
CIO Cap:	?

CIO @ 1.5X	1.9%
CIO @ 2X	2.5%

PGE Increment:	$ 44,700,991
Staff Increment:	$ 40,000,000
Staff Multiplier (SM2):	0.89

CATEGORY	Rate Schedule (1)	Present Revenues ($) Base Rates (2)	Present Revenues ($) Net Rates (3)	Proposed Base Rates (4)	PGE Filed CIO Revenues (5)	PGE Difference (6) (4) - (2) - (5)	Apply Staff Multiplier (7) (6) * (SM)	Revenues for CIO @ 2X @ Staff RR (8)	Staff Estimated Base Rates (9) (2) + (7) + (8)
Residential	7	$ 718,962,868	$ 635,784,749	$ 761,181,928	$ 1,504,884	$ 40,714,176	$ 16,611,915	$ 601,954	$ 736,176,737
Employee Discount		$ (770,359)	$ (684,662)	$ (817,793)					
Subtotal		$ 718,192,508	$ 635,100,087	$ 760,364,135	$ 1,504,884	$ 40,666,742	$ 16,592,562	$ 601,954	$ 735,387,024
Outdoor Area Lighting	15	$ 4,196,109	$ 4,133,012	$ 4,450,894	$ 4,699	$ 250,086	$ 102,039	$ 1,860	$ 4,300,027
General Service <30 kW	32	$ 131,132,120	$ 129,641,279	$ 142,416,923	$ 300,609	$ 10,984,194	$ 4,481,695	$ 120,244	$ 135,734,058
Opt. Time-of-Day G.S. >30 kW	38	$ 9,057,369	$ 9,056,184	$ 10,093,196	$ -	$ 1,035,827	$ 422,631	$ -	$ 9,480,000
Irrig. & Drain. Pump. < 30 kW	47	$ 1,916,636	$ 1,682,697	$ 2,159,459	$ (847,647)	$ 1,090,470	$ 444,926	$ (347,952)	$ 2,013,610
Irrig. & Drain. Pump. > 30 kW	49	$ 4,340,977	$ 3,694,522	$ 4,890,594	$ (2,101,736)	$ 2,651,352	$ 1,081,786	$ (862,303)	$ 4,560,461
General Service >30 kW									
Secondary	83-S	$ 373,440,731	$ 373,803,541	$ 398,171,209	$ 1,080,574	$ 23,649,905	$ 9,649,470	$ 432,230	$ 383,522,430
Primary	83-P	$ 18,670,550	$ 18,760,067	$ 20,692,372	$ 59,714	$ 1,962,108	$ 800,566	$ 23,886	$ 19,495,001
Schedule 89 > 1 MW									
Secondary	89-S	$ 45,904,320	$ 46,378,229	$ 46,932,813	$ 133,495	$ 894,998	$ 365,171	$ 53,398	$ 46,322,889
Primary	89-P	$ 148,087,674	$ 149,758,830	$ 155,759,641	$ 498,853	$ 7,173,115	$ 2,926,725	$ 199,541	$ 151,213,939
Subtransmission	89-T	$ 73,564,085	$ 74,460,512	$ 78,565,798	$ 271,644	$ 4,730,068	$ 1,929,930	$ 108,658	$ 75,602,673
Street & Highway Lighting	91	$ 14,551,163	$ 14,620,605	$ 16,392,774	$ (906,662)	$ 2,748,272	$ 1,121,331	$ (385,356)	$ 15,287,138
Traffic Signals	92	$ 390,786	$ 395,062	$ 440,258	$ (17,876)	$ 67,348	$ 27,479	$ (7,721)	$ 410,544
Recreational Field Lighting	93	$ 79,596	$ 80,167	$ 89,672	$ (6,923)	$ 16,999	$ 6,936	$ (2,910)	$ 83,621
TOTAL (CYCLE YEAR BASIS)		$ 1,543,524,623	$ 1,461,564,795	$ 1,641,419,738		$ 97,895,115	$ 39,942,485		$ 1,583,413,415
CONVERSION ADJUSTMENT		$ *2,222,575*	$ *2,104,558*	$ *2,363,537*		$ *140,963*	$ *57,515*		$ *2,280,012*
TOTAL (CALENDAR YEAR BASIS)		$ 1,545,747,198	$ 1,463,669,353	$ 1,643,783,275		$ 98,036,077	$ 40,000,000		$ 1,585,693,427

CATEGORY	Base Rates Jan 07 ($) (10) (9) - (2)	Base Rates Jan 07 (%) (11) (9) / (2)	PGE Total Supplementals (10)	Staff Estimated Net Rates (12) (9) + (10)	Net Rates Jan 07 ($) (13) (12) - (3)	Net Rates Jan 07 (%) (14) (12) / (3)	PGE PW Increment (15)	Apply Staff Multiplier (16) (15) * (SM2)	Staff Estimated Net Rates W/ Increment (17) (12) + (17)	Net Rate Increment March 07 ($) (18) (17) - (12)	Net Rate Increment March 07 (%) (19) (17) / (12)
Residential			$ (89,197,655)	$ 646,979,082			$17,832,877				
Employee Discount							($19,589)				
Subtotal	$ 17,194,516	2.39%	$ (89,197,655)	$ 646,189,369	$ 11,089,281	1.75%	$17,813,289	$ 15,939,950	$ 662,129,319	$ 15,939,950	2.47%
Outdoor Area Lighting	$ 103,918	2.48%	$ (88,237)	$ 4,211,790	$ 78,777	1.91%	$52,396	$ 46,886	$ 4,258,676	$ 46,886	1.11%
General Service <30 kW	$ 4,601,938	3.51%	$ (2,663,216)	$ 133,070,842	$ 3,429,563	2.65%	$3,532,156	$ 3,160,696	$ 136,231,538	$ 3,160,696	2.38%
Opt. Time-of-Day G.S. >30 kW	$ 422,631	4.67%	$ (69,974)	$ 9,410,026	$ 353,842	3.91%	$239,173	$ 214,020	$ 9,624,046	$ 214,020	2.27%
Irrig. & Drain. Pump. < 30 kW	$ 96,974	5.06%	$ (249,296)	$ 1,764,313	$ 81,616	4.85%	$49,053	$ 43,894	$ 1,808,207	$ 43,894	2.49%
Irrig. & Drain. Pump. > 30 kW	$ 219,483	5.06%	$ (685,187)	$ 3,875,274	$ 180,751	4.89%	$142,698	$ 127,691	$ 4,002,965	$ 127,691	3.30%
General Service >30 kW											
Secondary	$ 10,081,700	2.70%	$ (2,662,797)	$ 380,859,633	$ 7,056,092	1.89%	$12,246,408	$ 10,958,512	$ 391,818,145	$ 10,958,512	2.88%
Primary	$ 824,451	4.42%	$ (53,796)	$ 19,441,205	$ 681,137	3.63%	$651,479	$ 582,966	$ 20,024,170	$ 582,966	3.00%
Schedule 89 > 1 MW											
Secondary	$ 418,569	0.91%	$ 100,122	$ 46,423,010	$ 44,782	0.10%	$1,512,524	$ 1,353,459	$ 47,776,470	$ 1,353,459	2.92%
Primary	$ 3,126,266	2.11%	$ 473,910	$ 151,687,849	$ 1,929,019	1.29%	$5,318,162	$ 4,758,876	$ 156,446,726	$ 4,758,876	3.14%
Subtransmission	$ 2,038,587	2.77%	$ 261,651	$ 75,864,323	$ 1,403,812	1.89%	$2,847,771	$ 2,548,284	$ 78,412,608	$ 2,548,284	3.36%
Street & Highway Lighting	$ 735,975	5.06%	$ (27,386)	$ 15,259,753	$ 639,147	4.37%	$217,129	$ 194,295	$ 15,454,047	$ 194,295	1.27%
Traffic Signals	$ 19,758	5.06%	$ 891	$ 411,435	$ 16,373	4.14%	$13,185	$ 11,798	$ 423,233	$ 11,798	2.87%
Recreational Field Lighting	$ 4,025	5.06%	$ (136)	$ 83,486	$ 3,319	4.14%	$1,294	$ 1,158	$ 84,644	$ 1,158	1.39%
TOTAL (CYCLE YEAR BASIS)	$ 39,888,792	2.58%	$ (184,056,762)	$ 1,488,552,308	$ 26,987,513	1.85%	$44,636,717	$ 39,942,485	$ 1,528,494,794	$ 39,942,485	2.68%
CONVERSION ADJUSTMENT				$ *2,143,418*			$ *64,274*	$ *57,515*	$ *2,200,933*	$ *57,515*	
TOTAL (CALENDAR YEAR BASIS)	$ 39,946,229	2.58%		$ 1,490,695,726	$ 27,026,374	1.85%	$ 44,700,991	$ 40,000,000	$ 1,530,695,726	$ 40,000,000	2.68%

PGE Increase:	$ 98,036,077
Staff Increase:	$ 40,000,000
Staff Multiplier (SM):	0.41
CIO Cap:	2

CIO @ 1.5X	3.8%
CIO @ 2X	5.1%

PGE Increment:	$ 44,700,991
Staff Increment:	$ 40,000,000
Staff Multiplier (SM2):	0.89

CATEGORY	Rate Schedule (1)	Present Revenues ($) Base Rates (2)	Present Revenues ($) Net Rates (3)	Proposed Base Rates (4)	PGE Filed CIO Revenues (5)	PGE Difference (6) (4) - (2) - (5)	Apply Staff Multiplier (7) (6) * (SM)	Revenues for CIO @ 2X @ Staff RR (8)	Staff Estimated Base Rates (9) (2) + (7) + (8)	Base Rates Jan 07 ($) (10) (9) - (2)	Base Rates Jan 07 (%) (11) (9) / (2)	PGE Total Supplementals (10)	Staff Estimated Net Rates (12) (9) + (10)	Net Rates Jan 07 ($) (13) (12) - (3)	Net Rates Jan 07 (%) (14) (12) / (3)	PGE PW Increment (15)	Apply Staff Multiplier (16) (15) * (SM2)	Staff Estimated Net Rates W/ Increment (17) (12) + (17)	Net Rate Increment March 07 ($) (18) (17) - (12)	Net Rate Increment March 07 (%) (19) (17) / (12)
Residential	7	$ 718,962,868	$ 635,784,749	$ 761,181,928	$ 1,504,884	$ 40,714,176	$ 24,917,873	$ 902,931	$ 744,783,672			$ (89,197,655)	$ 655,586,016			$17,832,877				
Employee Discount		$ (770,359)	$ (684,662)	$ (817,793)												($19,589)				
Subtotal		$ 718,192,508	$ 635,100,087	$ 760,364,135	$ 1,504,884	$ 40,666,742	$ 24,888,843	$ 902,931	$ 743,984,282	$ 25,791,773	3.59%	$ (89,197,655)	$ 654,786,627	$ 19,686,539	3.10%	$17,813,289	$ 15,939,950	$ 670,726,577	$ 15,939,950	2.43%
Outdoor Area Lighting	15	$ 4,196,109	$ 4,133,012	$ 4,450,894	$ 4,699	$ 250,086	$ 153,058	$ 2,820	$ 4,351,986	$ 155,877	3.71%	$ (88,237)	$ 4,263,749	$ 130,737	3.16%	$52,396	$ 46,886	$ 4,310,635	$ 46,886	1.10%
General Service <30 kW	32	$ 131,132,120	$ 129,641,279	$ 142,416,923	$ 300,609	$ 10,984,194	$ 6,722,542	$ 180,365	$ 138,035,027	$ 6,902,907	5.26%	$ (2,663,216)	$ 135,371,811	$ 5,730,532	4.42%	$3,532,156	$ 3,160,696	$ 138,532,507	$ 3,160,696	2.33%
Opt. Time-of-Day G.S. >30 kW	38	$ 9,057,369	$ 9,056,184	$ 10,093,196	$ -	$ 1,035,827	$ 633,947	$ -	$ 9,691,315	$ 633,947	7.00%	$ (69,974)	$ 9,621,342	$ 566,158	6.24%	$239,173	$ 214,020	$ 9,835,362	$ 214,020	2.22%
Irrig. & Drain. Pump. < 30 kW	47	$ 1,916,636	$ 1,682,697	$ 2,159,459	$ (847,647)	$ 1,090,470	$ 667,389	$ (521,012)	$ 2,063,013	$ 146,378	7.64%	$ (249,296)	$ 1,813,717	$ 131,020	7.79%	$49,053	$ 43,894	$ 1,857,611	$ 43,894	2.42%
Irrig. & Drain. Pump. > 30 kW	49	$ 4,340,977	$ 3,694,522	$ 4,890,594	$ (2,101,736)	$ 2,651,352	$ 1,622,680	$ (1,291,076)	$ 4,672,581	$ 331,603	7.64%	$ (685,187)	$ 3,987,394	$ 292,871	7.93%	$142,698	$ 127,691	$ 4,115,085	$ 127,691	3.20%
General Service >30 kW																				
Secondary	83-S	$ 373,440,731	$ 373,803,641	$ 398,171,209	$ 1,080,574	$ 23,649,905	$ 14,474,205	$ 648,344	$ 388,563,280	$ 15,122,549	4.05%	$ (2,662,797)	$ 385,900,483	$ 12,096,942	3.24%	$12,246,408	$ 10,958,512	$ 396,858,995	$ 10,958,512	2.84%
Primary	83-P	$ 18,670,550	$ 18,760,067	$ 20,692,372	$ 59,714	$ 1,962,108	$ 1,200,848	$ 35,828	$ 19,907,227	$ 1,236,677	6.62%	$ (53,796)	$ 19,853,430	$ 1,093,363	5.83%	$651,479	$ 582,966	$ 20,436,396	$ 582,966	2.94%
Schedule 89 > 1 MW																				
Secondary	89-S	$ 45,904,320	$ 46,378,229	$ 46,932,813	$ 133,495	$ 894,998	$ 547,756	$ 80,097	$ 46,532,173	$ 627,854	1.37%	$ 100,122	$ 46,632,295	$ 254,066	0.55%	$1,512,524	$ 1,353,459	$ 47,985,754	$ 1,353,459	2.90%
Primary	89-P	$ 148,087,674	$ 149,758,830	$ 155,759,641	$ 498,853	$ 7,173,115	$ 4,390,087	$ 299,312	$ 152,777,072	$ 4,689,399	3.17%	$ 473,910	$ 153,250,982	$ 3,492,152	2.33%	$5,318,162	$ 4,758,876	$ 158,009,858	$ 4,758,876	3.11%
Subtransmission	89-T	$ 73,564,085	$ 74,460,512	$ 78,565,798	$ 271,644	$ 4,730,068	$ 2,894,895	$ 162,987	$ 76,621,966	$ 3,057,881	4.16%	$ 261,651	$ 76,883,617	$ 2,423,105	3.25%	$2,847,771	$ 2,548,284	$ 79,431,902	$ 2,548,284	3.31%
Street & Highway Lighting	91	$ 14,551,163	$ 14,620,605	$ 16,392,774	$ (906,662)	$ 2,748,272	$ 1,681,996	$ (570,209)	$ 15,662,950	$ 1,111,787	7.64%	$ (27,386)	$ 15,635,565	$ 1,014,959	6.94%	$217,129	$ 194,295	$ 15,829,860	$ 194,295	1.24%
Traffic Signals	92	$ 390,786	$ 395,062	$ 440,258	$ (17,876)	$ 67,348	$ 41,218	$ (11,343)	$ 420,661	$ 29,875	7.64%	$ 891	$ 421,552	$ 26,490	6.71%	$13,185	$ 11,798	$ 433,350	$ 11,798	2.80%
Recreational Field Lighting	93	$ 79,596	$ 80,167	$ 89,672	$ (6,923)	$ 16,999	$ 10,403	$ (4,323)	$ 85,676	$ 6,080	7.64%	$ (136)	$ 85,541	$ 5,374	6.70%	$1,294	$ 1,158	$ 86,699	$ 1,158	1.35%
TOTAL (CYCLE YEAR BASIS)		$ 1,543,524,623	$ 1,461,564,795	$ 1,641,419,738		$ 97,895,115	$ 59,913,728		$ 1,603,369,211	$ 59,844,588	3.88%	$ (184,058,762)	$ 1,508,508,104	$ 46,943,309	3.21%	$44,636,717	$ 39,942,485	$ 1,548,450,589	$ 39,942,485	2.65%
CONVERSION ADJUSTMENT		*$ 2,222,576*	*$ 2,104,558*	*$ 2,363,537*		*$ 140,963*	*$ 86,272*		*$ 2,308,747*				*$ 2,172,153*			*$ 64,274*	*$ 57,516*	*$ 2,229,668*	*$ 57,516*	
TOTAL (CALENDAR YEAR BASIS)		$ 1,545,747,198	$ 1,463,669,353	$ 1,643,783,275		$ 98,036,077	$ 60,000,000		$ 1,605,677,958	$ 59,930,760	3.88%		$ 1,510,680,257	$ 47,010,904	3.21%	$ 44,700,991	$ 40,000,000	$ 1,550,680,257	$ 40,000,000	2.65%

PGE Increase:	$ 98,036,077
Staff Increase:	$ 60,000,000
Staff Multiplier (SM):	0.61
CIO Cap:	2

CIO @ 1.5X	5.7%
CIO @ 2X	7.6%

PGE Increment:	$ 44,700,991
Staff Increment:	$ 40,000,000
Staff Multiplier (SM2):	0.89

CATEGORY	Rate Schedule (1)	Present Revenues ($) Base Rates (2)	Present Revenues ($) Net Rates (3)	Proposed Base Rates (4)	PGE Filed CIO Revenues (5)	PGE Difference (6) (4) - (2) - (5)	Apply Staff Multiplier (7) (6) * (SM)	Revenues for CIO @ 2X @ Staff RR (8)	Staff Estimated Base Rates (9) (2) + (7) + (8)	Base Rates Jan 07 ($) (10) (9) - (2)	Base Rates Jan 07 (%) (11) (9) / (2)	PGE Total Supplementals (10)	Staff Estimated Net Rates (12) (9) + (10)	Net Rates Jan 07 ($) (13) (12) - (3)	Net Rates Jan 07 (%) (14) (12) / (3)	PGE PW Increment (15)	Apply Staff Multiplier (16) (15) * (SM2)	Staff Estimated Net Rates W/ Increment (17) (12) + (17)	Net Rate Increment March 07 ($) (18) (17) - (12)	Net Rate Increment March 07 (%) (19) (17) / (12)
Residential	7	$ 718,962,868	$ 635,784,749	$ 761,181,928	$ 1,504,884	$ 40,714,176	$ 33,223,831	$ 1,203,907	$ 753,390,606			$ (89,197,655)	$ 664,192,951			$17,832,877				
Employee Discount		$ (770,359)	$ (684,662)	$ (817,793)												($19,589)				
Subtotal		$ 718,192,508	$ 635,100,087	$ 760,364,135	$ 1,504,884	$ 40,666,742	$ 33,185,124	$ 1,203,907	$ 752,581,540	$ 34,389,031	4.79%	$ (89,197,655)	$ 663,383,884	$ 28,283,797	4.45%	$17,813,289	$ 15,939,950	$ 679,323,834	$ 15,939,950	2.40%
Outdoor Area Lighting	15	$ 4,196,109	$ 4,133,012	$ 4,450,894	$ 4,699	$ 250,086	$ 204,077	$ 3,759	$ 4,403,945	$ 207,836	4.95%	$ (88,237)	$ 4,315,708	$ 182,696	4.42%	$52,396	$ 46,886	$ 4,362,594	$ 46,886	1.09%
General Service <30 kW	32	$ 131,132,120	$ 129,641,279	$ 142,416,923	$ 300,609	$ 10,984,194	$ 8,963,389	$ 240,487	$ 140,335,996	$ 9,203,876	7.02%	$ (2,663,216)	$ 137,672,780	$ 8,031,501	6.20%	$3,532,156	$ 3,160,696	$ 140,833,476	$ 3,160,696	2.30%
Opt. Time-of-Day G.S. >30 kW	38	$ 9,057,369	$ 9,056,184	$ 10,093,196	$ -	$ 1,035,827	$ 845,262	$ -	$ 9,902,631	$ 845,262	9.33%	$ (69,974)	$ 9,832,657	$ 776,473	8.57%	$239,173	$ 214,020	$ 10,046,678	$ 214,020	2.18%
Irrig. & Drain. Pump. < 30 kW	47	$ 1,916,636	$ 1,682,697	$ 2,159,459	$ (847,647)	$ 1,090,470	$ 889,852	$ (693,612)	$ 2,112,876	$ 196,240	10.24%	$ (249,296)	$ 1,863,579	$ 180,882	10.75%	$49,053	$ 43,894	$ 1,907,473	$ 43,894	2.36%
Irrig. & Drain. Pump. > 30 kW	49	$ 4,340,977	$ 3,694,522	$ 4,890,594	$ (2,101,736)	$ 2,651,352	$ 2,163,573	$ (1,719,170)	$ 4,785,380	$ 444,403	10.24%	$ (685,187)	$ 4,100,193	$ 405,671	10.98%	$142,698	$ 127,691	$ 4,227,884	$ 127,691	3.11%
General Service >30 kW																				
Secondary	83-S	$ 373,440,731	$ 373,803,541	$ 398,171,209	$ 1,080,574	$ 23,649,905	$ 19,298,940	$ 864,459	$ 393,604,130	$ 20,163,399	5.40%	$ (2,662,797)	$ 390,941,333	$ 17,137,792	4.58%	$12,246,408	$ 10,958,512	$ 401,899,845	$ 10,958,512	2.80%
Primary	83-P	$ 18,670,550	$ 18,760,067	$ 20,692,372	$ 59,714	$ 1,962,108	$ 1,601,131	$ 47,771	$ 20,319,452	$ 1,648,902	8.83%	$ (53,796)	$ 20,265,656	$ 1,505,589	8.03%	$651,479	$ 582,966	$ 20,848,621	$ 582,966	2.88%
Schedule 89 > 1 MW																				
Secondary	89-S	$ 45,904,320	$ 46,378,229	$ 46,932,813	$ 133,495	$ 894,998	$ 730,342	$ 106,796	$ 46,741,458	$ 837,138	1.82%	$ 100,122	$ 46,841,579	$ 463,351	1.00%	$1,512,524	$ 1,353,459	$ 48,195,039	$ 1,353,459	2.89%
Primary	89-P	$ 148,087,674	$ 149,758,830	$ 155,759,641	$ 498,853	$ 7,173,115	$ 5,853,449	$ 399,082	$ 154,340,205	$ 6,252,531	4.22%	$ 473,910	$ 154,814,115	$ 5,055,285	3.36%	$5,318,162	$ 4,758,876	$ 159,572,991	$ 4,758,876	3.07%
Subtransmission	89-T	$ 73,564,085	$ 74,460,512	$ 78,565,798	$ 271,644	$ 4,730,068	$ 3,859,859	$ 217,316	$ 77,641,260	$ 4,077,175	5.54%	$ 261,651	$ 77,902,911	$ 3,442,399	4.62%	$2,847,771	$ 2,548,284	$ 80,451,195	$ 2,548,284	3.27%
Street & Highway Lighting	91	$ 14,551,163	$ 14,620,605	$ 16,392,774	$ (906,662)	$ 2,748,272	$ 2,242,662	$ (753,106)	$ 16,040,719	$ 1,489,556	10.24%	$ (27,386)	$ 16,013,333	$ 1,392,728	9.63%	$217,129	$ 194,295	$ 16,207,628	$ 194,295	1.21%
Traffic Signals	92	$ 390,786	$ 395,062	$ 440,258	$ (17,876)	$ 67,348	$ 54,958	$ (14,966)	$ 430,776	$ 39,992	10.23%	$ 891	$ 431,669	$ 36,606	9.27%	$13,185	$ 11,798	$ 443,467	$ 11,798	2.73%
Recreational Field Lighting	93	$ 79,596	$ 80,167	$ 89,672	$ (6,923)	$ 16,999	$ 13,871	$ (5,719)	$ 87,748	$ 8,152	10.24%	$ (136)	$ 87,613	$ 7,446	9.29%	$1,294	$ 1,158	$ 88,771	$ 1,158	1.32%
TOTAL (CYCLE YEAR BASIS)		$ 1,543,524,623	$ 1,461,564,795	$ 1,641,419,738		$ 97,895,115	$ 79,884,971		$ 1,623,328,117	$ 79,803,494	5.17%	$ (184,058,762)	$ 1,528,467,011	$ 66,902,216	4.58%	$44,636,717	$ 39,942,485	$ 1,568,409,496	$ 39,942,485	2.61%
CONVERSION ADJUSTMENT		*$ 2,222,575*	*$ 2,104,558*	*$ 2,363,537*		*$ 140,963*	*$ 115,029*		*$ 2,337,487*				*$ 2,200,893*			*$ 64,274*	*$ 57,515*	*$ 2,258,407*	*$ 57,515*	
TOTAL (CALENDAR YEAR BASIS)		$ 1,545,747,198	$ 1,463,669,353	$ 1,643,783,275		$ 98,036,077	$ 80,000,000		$ 1,625,665,604	$ 79,918,406	5.17%		$ 1,530,667,903	$ 66,998,550	4.58%	$ 44,700,991	$ 40,000,000	$ 1,570,667,903	$ 40,000,000	2.61%

PGE Increase:	$ 98,036,077
Staff Increase:	$ 80,000,000
Staff Multiplier (SM):	0.82
CIO Cap:	?

CIO @ 1.5X	7.7%
CIO @ 2X	10.2%

PGE Increment:	$ 44,700,991
Staff Increment:	$ 40,000,000
Staff Multiplier (SM2):	0.89

CATEGORY	Rate Schedule (1)	Present Revenues ($) Base Rates (2)	Present Revenues ($) Net Rates (3)	Proposed Base Rates (4)	PGE Filed CIO Revenues (5)	PGE Difference (6) (4) - (2) - (5)	Apply Staff Multiplier (7) (6) * (SM)	Revenues for CIO @ 2X @ Staff RR (8)	Staff Estimated Base Rates (9) (2) + (7) + (8)
Residential	7	$ 718,962,868	$ 635,784,749	$ 761,181,928	$ 1,504,884	$ 40,714,176	$ 41,529,789	$ 1,580,128	$ 762,072,785
Employee Discount		$ (770,359)	$ (684,662)	$ (817,793)					
Subtotal		$ 718,192,508	$ 635,100,087	$ 760,364,135	$ 1,504,884	$ 40,666,742	$ 41,481,405	$ 1,580,128	$ 761,254,042
Outdoor Area Lighting	15	$ 4,196,109	$ 4,133,012	$ 4,450,894	$ 4,699	$ 250,086	$ 255,096	$ 4,934	$ 4,456,139
General Service <30 kW	32	$ 131,132,120	$ 129,641,279	$ 142,416,923	$ 300,609	$ 10,984,194	$ 11,204,237	$ 315,639	$ 142,651,996
Opt. Time-of-Day G.S. >30 kW	38	$ 9,057,369	$ 9,056,184	$ 10,093,196	$ -	$ 1,035,827	$ 1,056,578	$ -	$ 10,113,946
Irrig. & Drain. Pump. < 30 kW	47	$ 1,916,636	$ 1,682,697	$ 2,159,459	$ (847,647)	$ 1,090,470	$ 1,112,315	$ (866,672)	$ 2,162,279
Irrig. & Drain. Pump. > 30 kW	49	$ 4,340,977	$ 3,694,522	$ 4,890,594	$ (2,101,736)	$ 2,651,352	$ 2,704,466	$ (2,147,943)	$ 4,897,500
General Service >30 kW									
Secondary	83-S	$ 373,440,731	$ 373,803,541	$ 398,171,209	$ 1,080,574	$ 23,649,905	$ 24,123,675	$ 1,134,603	$ 398,699,008
Primary	83-P	$ 18,670,550	$ 18,760,067	$ 20,692,372	$ 59,714	$ 1,962,108	$ 2,001,414	$ 62,700	$ 20,734,663
Schedule 89 > 1 MW									
Secondary	89-S	$ 45,904,320	$ 46,378,229	$ 46,932,813	$ 133,495	$ 894,998	$ 912,927	$ 140,170	$ 46,957,417
Primary	89-P	$ 148,087,674	$ 149,758,830	$ 155,759,641	$ 498,853	$ 7,173,115	$ 7,316,812	$ 523,795	$ 155,928,280
Subtransmission	89-T	$ 73,564,085	$ 74,460,512	$ 78,565,798	$ 271,644	$ 4,730,068	$ 4,824,824	$ 285,227	$ 78,674,136
Street & Highway Lighting	91	$ 14,551,163	$ 14,620,605	$ 16,392,774	$ (906,662)	$ 2,748,272	$ 2,803,327	$ (937,960)	$ 16,416,531
Traffic Signals	92	$ 390,786	$ 395,062	$ 440,258	$ (17,876)	$ 67,348	$ 68,697	$ (18,589)	$ 440,895
Recreational Field Lighting	93	$ 79,596	$ 80,167	$ 89,672	$ (6,923)	$ 16,999	$ 17,339	$ (7,137)	$ 89,798
TOTAL (CYCLE YEAR BASIS)		$ 1,543,524,623	$ 1,461,564,795	$ 1,641,419,738		$ 97,895,115	$ 99,856,214		$ 1,643,476,631
CONVERSION ADJUSTMENT		$ *2,222,575*	$ *2,104,558*	$ *2,363,537*		$ *140,963*	$ *143,786*		$ *2,366,499*
TOTAL (CALENDAR YEAR BASIS)		$ 1,545,747,198	$ 1,463,669,353	$ 1,643,783,275		$ 98,036,077	$ 100,000,000		$ 1,645,843,130

CATEGORY	Base Rates Jan 07 ($) (10) (9) - (2)	Base Rates Jan 07 (%) (11) (9) / (2)	PGE Total Supplementals (10)	Staff Estimated Net Rates (12) (9) + (10)	Net Rates Jan 07 ($) (13) (12) - (3)	Net Rates Jan 07 (%) (14) (12) / (3)	PGE PW Increment (15)	Apply Staff Multiplier (16) (15) * (SM2)	Staff Estimated Net Rates W/ Increment (17) (12) + (17)	Net Rate Increment March 07 ($) (18) (17) - (12)	Net Rate Increment March 07 (%) (19) (17) / (12)
Residential			$ (89,197,655)	$ 672,875,130			$17,832,877				
Employee Discount							($19,589)				
Subtotal	$ 43,061,533	6.00%	$ (89,197,655)	$ 672,056,386	$ 36,956,299	5.82%	$17,813,289	$ 15,939,950	$ 687,996,336	$ 15,939,950	2.37%
Outdoor Area Lighting	$ 260,030	6.20%	$ (88,237)	$ 4,367,902	$ 234,890	5.68%	$52,396	$ 46,886	$ 4,414,788	$ 46,886	1.07%
General Service <30 kW	$ 11,519,876	8.78%	$ (2,663,216)	$ 139,988,780	$ 10,347,501	7.98%	$3,532,156	$ 3,160,696	$ 143,149,476	$ 3,160,696	2.26%
Opt. Time-of-Day G.S. >30 kW	$ 1,056,578	11.67%	$ (69,974)	$ 10,043,973	$ 987,789	10.91%	$239,173	$ 214,020	$ 10,257,993	$ 214,020	2.13%
Irrig. & Drain. Pump. < 30 kW	$ 245,643	12.82%	$ (249,296)	$ 1,912,983	$ 230,286	13.69%	$49,053	$ 43,894	$ 1,956,877	$ 43,894	2.29%
Irrig. & Drain. Pump. > 30 kW	$ 556,523	12.82%	$ (685,187)	$ 4,212,313	$ 517,791	14.02%	$142,698	$ 127,691	$ 4,340,004	$ 127,691	3.03%
General Service >30 kW											
Secondary	$ 25,258,278	6.76%	$ (2,662,797)	$ 396,036,211	$ 22,232,670	5.95%	$12,246,408	$ 10,958,512	$ 406,994,723	$ 10,958,512	2.77%
Primary	$ 2,064,113	11.06%	$ (53,796)	$ 20,680,867	$ 1,920,800	10.24%	$651,479	$ 582,966	$ 21,263,833	$ 582,966	2.82%
Schedule 89 > 1 MW											
Secondary	$ 1,053,097	2.29%	$ 100,122	$ 47,057,539	$ 679,310	1.46%	$1,612,524	$ 1,353,459	$ 48,410,998	$ 1,353,459	2.88%
Primary	$ 7,840,607	5.29%	$ 473,910	$ 156,402,191	$ 6,643,361	4.44%	$5,318,162	$ 4,758,876	$ 161,161,067	$ 4,758,876	3.04%
Subtransmission	$ 5,110,051	6.95%	$ 261,651	$ 78,935,787	$ 4,475,275	6.01%	$2,847,771	$ 2,548,284	$ 81,484,071	$ 2,548,284	3.23%
Street & Highway Lighting	$ 1,865,368	12.82%	$ (27,386)	$ 16,389,145	$ 1,768,540	12.10%	$217,129	$ 194,295	$ 16,583,440	$ 194,295	1.19%
Traffic Signals	$ 50,108	12.82%	$ 891	$ 441,785	$ 46,723	11.83%	$13,185	$ 11,798	$ 453,583	$ 11,798	2.67%
Recreational Field Lighting	$ 10,202	12.82%	$ (136)	$ 89,662	$ 9,495	11.84%	$1,294	$ 1,158	$ 90,820	$ 1,158	1.29%
TOTAL (CYCLE YEAR BASIS)	$ 99,952,008	6.48%	$ (184,058,762)	$ 1,548,615,524	$ 87,050,729	5.96%	$44,636,717	$ 39,942,485	$ 1,588,558,010	$ 39,942,485	2.58%
CONVERSION ADJUSTMENT				$ *2,229,906*			$ *64,274*	$ *57,516*	$ *2,287,420*	$ *57,516*	
TOTAL (CALENDAR YEAR BASIS)	$ 100,095,933	6.48%		$ 1,550,845,430	$ 87,176,077	5.96%	$ 44,700,991	$ 40,000,000	$ 1,590,845,430	$ 40,000,000	2.58%

PGE Increase:	$ 98,036,077
Staff Increase:	$ 100,000,000
Staff Multiplier (SM):	1.02
CIO Cap:	?

CIO @ 1.5X	9.6%
CIO @ 2X	12.8%

PGE Increment:	$ 44,700,991
Staff Increment:	$ 40,000,000
Staff Multiplier (SM2):	0.89

CERTIFICATE OF SERVICE

UE 180/UE 181/UE 184

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 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 9th of August, 2006.

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Assistant Attorney General
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