Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8982 • Facsimile (503) 464-2222

James J. Piro, P.E.
Executive Vice President, Finance
Chief Financial Officer & Treasurer

February 27, 2008

Public Utility Commission of Oregon
Attn: Filing Center
550 Capitol Street, N.E., Suite 215
Salem, OR 97301-2551

RE: **Advice No. 08-02, PGE General Rate Case**

Enclosed for filing is the original and one conformed copy of revised Tariff sheets, with an effective date of **April 1, 2008**:

Third Revision of Sheet No. 1-2
Third Revision of Sheet No. 7-1
Second Revision of Sheet No. 15-1
Second Revision of Sheet No. 15-2
Second Revision of Sheet No. 15-3
First Revision of Sheet No. 15-4
Second Revision of Sheet No. 32-1
First Revision of Sheet No. 32-4
Third Revision of Sheet No. 38-1
Second Revision of Sheet No. 38-3
Second Revision of Sheet No. 47-1
Third Revision of Sheet No. 49-1
Third Revision of Sheet No. 75-1
First Revision of Sheet No. 75-5
Third Revision of Sheet No. 76R-1
First Revision of Sheet No. 76R-3
First Revision of Sheet No. 76R-4
First Revision of Sheet No. 76R-5
Second Revision of Sheet No. 81-1
Third Revision of Sheet No. 83-1
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While we are filing tariffs with an effective date of April 1, 2008, we expect this filing to be suspended for investigation. We request that a prehearing conference be held expeditiously to establish a schedule that will allow revised prices to become effective January 1, 2009.

By April 1st, we will file the remaining power cost updates. We expect that any errata corrections identified in the material herein presented will be filed by early April.

To ensure a timely response, please direct your communications related to this filing to the following email address: pge.opuc.filings@pgn.com

Please mail hardcopies to:

Rates and Regulatory Affairs
121 SW Salmon St, 1WTC0702
Portland, Oregon 97204
(503) 464-7857

Doug Tingey
121 SW Salmon St, 1WTC1301
Portland, Oregon 97204
(503) 464-8926

Sincerely,

James J. Piro

James J. Piro
CFO & Executive Vice President of Finance

cc: Service List – UE 188

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CFO & Executive Vice President of Finance

cc: Service List – UE 188

PORTLAND GENERAL ELECTRIC COMPANY
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RATE SCHEDULES

Schedule **Description**

Standard Service Schedules (Continued)

Adjustment Schedules

SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$10.00		
Three Phase Service	$13.00		
Transmission and Related Services Charge	0.225	¢ per kWh	(I)
Distribution Charge	3.152	¢ per kWh	
Energy Charge			
Standard Service			
First 250 kWh	5.066	¢ per kWh	
Over 250 kWh	6.841	¢ per kWh	
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)			
On-Peak Period	11.778	¢ per kWh	
Mid-Peak Period	6.841	¢ per kWh	
Off-Peak Period	3.928	¢ per kWh	(I)
First 250 kWh block adjustment	(1.775)	¢ per kWh	
Nonstandard Metering Charge (applicable to TOU)			
Single Phase meter	$1.00		
Three Phase meter	$4.25		

* See Schedule 100 for applicable adjustments.

SCHEDULE 15
OUTDOOR AREA LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer notifies the Company of the burn-out.

MONTHLY RATE

Included in the service rates for each installed luminaire are the following pricing components:

Transmission and Related Services Charge	0.125	¢ per kWh	(I)
Distribution Charge	3.124	¢ per kWh	(R)
Cost of Service Energy Charge	5.857	¢ per kWh	(I)

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate [1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$11.69 [2]	(I)
	400	21,000	147	19.18 [2]	
	1,000	55,000	374	40.71 [2]	
HPS	70	6,300	30	8.20 [2]	
	100	9,500	43	9.48	
	150	16,000	62	11.24	
	200	22,000	79	13.24	
	250	29,000	102	15.39	
	310	37,000	124	18.13 [2]	
	400	50,000	163	20.97	
Flood, HPS	100	9,500	43	9.89 [2]	
	200	22,000	79	13.33 [2]	
	250	29,000	102	15.70	
	400	50,000	163	21.27	(I)
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	9.06	(N)
	100	9,500	43	10.40	(I)
	150	16,500	62	12.43	
Special Acorn Type, HPS	100	9,500	43	13.28	
HADCO Victorian, HPS	150	16,500	62	14.70	
	200	22,000	79	16.29	
	250	29,000	102	18.49	
Early American Post-Top, HPS Black	100	9,500	43	10.36	
Special Types					
Cobrahead, Metal Halide	175	12,000	71	12.27	
Flood, Metal Halide	400	40,000	156	20.63	
Flood, HPS	750	105,000	285	34.87	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Special Types (Continued)					
HADCO Independence, HPS	100	9,500	43	$12.50	(I)
	150	16,000	62	14.24	
HADCO Capitol Acorn, HPS	100	9,500	43	17.21	
	150	16,000	62	18.96	
	200	22,000	79	20.50	
	250	29,000	102	22.60	
HADCO Techtra, HPS	100	9,500	43	19.96	
	150	16,000	62	21.71	
	250	29,000	102	32.11	
KIM Archetype, HPS	250	29,000	102	19.95	
	400	50,000	163	25.32	
Holophane Mongoose, HPS	150	16,000	62	13.55	
	250	29,000	102	17.28	
	400	50,000	163	22.87	(I)

Rates for Area Light Poles

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$5.98	
	55 or less	7.51	
Wood, Painted for Underground	35 or less	6.99 [2]	
Wood, Curved Laminated	30 or less	8.68 [2]	(I)
Aluminum, Regular	16	7.40	
	25	12.03	(I)
	30	13.03	
	35	14.33	
Aluminum, Fluted Ornamental	14	14.07	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lights Poles[1] (Continued)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Aluminum Davit	25	$12.43	(I)
	30	13.25	
	35	14.65	
	40	17.88	
Aluminum Double Davit	30	15.95	
Aluminum, HADCO, Fluted Ornamental	16	13.47	
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	25.16	
Concrete Ameron Post-Top	25	29.74	
Fiberglass Fluted Ornamental; Black	14	8.22	(I)
Fiberglass, Regular			
Black	20	5.20	
Gray or Bronze	30	6.97	(I)
Other Colors (as available)	35	9.48	
Fiberglass, Anchor Base Gray	35	15.17	
Fiberglass, Direct Bury with Shroud	18	7.87	(I)

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$12.00		
Three Phase Service	$16.00		
Transmission and Related Services Charge	0.184	¢ per kWh	(R)
Distribution Charge			
First 5,000 kWh	2.987	¢ per kWh	(I)
Over 5,000 kWh	0.576	¢ per kWh	
Energy Charge			
Standard Service	6.356	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)			
On-Peak Period	10.812	¢ per kWh	
Mid-Peak Period	6.356	¢ per kWh	
Off-Peak Period	3.604	¢ per kWh	(I)
Nonstandard Metering Charge (applicable to TOU)			
Single Phase meter	$2.35		
Three Phase meter	$4.25		

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

DAILY PRICE

The Daily Price, applicable with Direct Access Service, is available to those Customers who were served under Schedule 532 and subsequently returned to this schedule before meeting the minimum term requirement of Schedule 532. The Customer will be charged the Daily Price and Nonstandard Metering charges of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index)
- plus 0.226¢ per kWh for wheeling (R)
- times a loss adjustment factor of 1.0834

If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. Customers served under this schedule may at any time notify the Company of their intent to choose Direct Access Service. Notification must conform to the requirements established in Rule K.

2. Customers must enroll to receive service under any portfolio option. Customers may initially enroll or make one portfolio change per year without incurring the Portfolio Enrollment Charge as specified in Schedule 300.

SCHEDULE 38
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY STANDARD SERVICE (COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00		
Transmission and Related Services Charge	0.099	¢ per kWh	(I)
Distribution Charge	3.875	¢ per kWh	
Energy Charge**			
On-Peak Period	7.097	¢ per kWh	
Off-Peak Period	5.637	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 38 (Concluded)

DIRECT ACCESS DEFAULT SERVICE

A Customer returning to Schedule 38 service before completing the term of service specified in Schedule 538, must be billed at the Daily Price for the remainder of the term. This provision does not eliminate the requirement to receive service on Schedule 81 when notice is insufficient. The Daily Price under this schedule is as follows:

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Quarterly Election Enrollment Window. (R)

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0834

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. Service under this schedule will begin on the first day of the Customer's regularly scheduled Billing Period.

2. In no case will the Company refund a Customer by retroactively adjusting the rate at which service was billed prior to the date the Customer begins service on this schedule.

3. Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 49% on-peak and 51% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 47
SMALL NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$25.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.208	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand	4.855	¢ per kWh	
Over 50 kWh per kW of Demand	2.855	¢ per kWh	
Energy Charge***	6.085	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$30.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.205	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand	3.276	¢ per kWh	
Over 50 kWh per kW of Demand	1.276	¢ per kWh	
Energy Charge***	6.118	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 30 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$160.00	$230.00	$1,000.00	
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.75	$0.75	$0.75	(I)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	
Over 1,000 kW	$0.61	$0.39	$0.39	(I)
per kW of monthly On-Peak Demand	$2.18	$2.18	$1.10	(R)
Generation Contingency Reserves Charges				
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.407 ¢	0.387 ¢	0.372 ¢	(R)(I)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.226¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, **(R)**
plus losses.

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:*

Transmission and Related Services Charge			
per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.029		(I)
Daily ERP Demand Charge			
	Delivery Voltage		
	Secondary and Primary	Subtransmission	
per kW of Daily ERP Demand during On-Peak hours per day**	$0.085	$0.043	(R)
System Usage Charge			
per kWh of ERP		0.372	(I)
Transaction Fee			
per Energy Needs Forecast (ENF)		$50.00	
Energy Charge*			
per kWh of ERP	See below for ERP Pricing		

* See Schedule 100 for applicable adjustments.
** Peak hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ENF Options for ERP (Continued)

The Daily ENF pre-scheduling protocols will conform to the standard practices, applicable definitions, requirements and schedules of the WECC. Pre-Schedule Day means the trading day immediately preceding the day of delivery consistent with WECC practices for Saturday, Sunday, Monday or holiday deliveries.

ERP Pricing

The following ERP Energy Charges are applied to the applicable hourly ENF and summed for the hours for the monthly billing:

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported. **(R)**

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.226¢ per kWh for wheeling, plus losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer's submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place. **(R)**

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.226¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. **(R)**

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing (Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

On-peak hours (Heavy Load Hours, HLH) are between 6:00 a.m. and 10:00 p.m. PPT (hours ending 0700 through 2200), Monday through Saturday. Off-peak hours (Light Load Hours, LLH) are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all hours Sunday.

Losses will be included by multiplying the ERP Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 75 Baseline Energy.

IMBALANCE ENERGY SETTLEMENT

Imbalance Settlement Amounts are bill credits or charges resulting from hourly Imbalance Energy multiplied by the applicable hourly Settlement Price and summed for all hours in the billing period. Imbalance Energy is the kWh amount determined hourly as the deviation between Actual Energy for such hour and the ENF for such hour (i.e., Imbalance Energy = Actual Energy less ENF).

For any Imbalance Energy in any hour up to 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive Imbalance Energy (where Customer receives more ERP than the ENF), the Imbalance Energy multiplied by the Settlement Price of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 0.226¢ per kWh for wheeling, plus losses. **(R)**
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index plus 0.226¢ per kWh for wheeling, plus losses. **(R)**

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

For any Imbalance Energy in any hour in excess of 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 10%, plus 0.226¢ per kWh for wheeling, plus losses. **(R)**
- For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index, less 10%, plus 0.226¢ per kWh for wheeling, **(R)** plus losses.

The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule N Curtailment Plan and Rule C (Section 2).

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Dow Jones Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. (R)

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

Losses will be included by multiplying the Energy Charge Daily Rate by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 1,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00	$80.00	(R)
Transmission and Related Services Charge			
per kW of monthly Demand	$0.75	$0.75	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 30 kW	$1.54	$1.81	(R)
Over 30 kW	$2.34	$1.81	(I)(N)
per kW of monthly Demand	$2.13	$2.13	(I)(R) (D)
Energy Charge			
Cost of Service Option per kWh	6.313 ¢	6.106 ¢	(I)
See below for Daily or Monthly Pricing Option descriptions.			
System Usage Charge			
per kWh	0.419 ¢	0.403 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON COST OF SERVICE OPTIONS

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Quarterly Election Enrollment Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

Monthly Fixed Price Option - A monthly fixed price per kWh quoted by the Company, differentiated by on- and off-peak hours for the next calendar month. The quote will be made on the 15th of the preceding month (or the following working day if the 15th is a weekend or holiday) by a posting on the Company's website (www.PortlandGeneral.biz) and will be based on the expected market price for power delivered to the Company's service territory plus losses. The Customer will notify the Company by 5:00 p.m. PPT on the business day following such posting of its choice of this option.

Non-Cost of Service Options are subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

SCHEDULE 87 (Continued)

STANDARD BILL

The Standard Bill is calculated by applying the Annual Cost of Service Option under Schedule 89 to a CBL for each month of the year, excluding the Reactive Demand Charge and Adjustments identified in Schedule 100. If prices are revised, those changes will be reflected in the Customer's Standard Bill based on the CBL for a given month. Hourly Energy prices are applied only to kWh usage changes from the CBL in each hour.

CUSTOMER BASELINE LOAD (CBL)

The CBL is the Customer's hourly load for a 12-month period at typical levels of operation. It is developed based on the Customer's specific hourly load data or monthly billing data allocated to hours based on the consumption pattern agreed to by the Customer and the Company as typical of the Customer's operation.

Agreement to a CBL is a precondition for service under this schedule. The CBL is proprietary and will not be released to any other entity without the approval of the Customer and the Company. In order that the CBL reflect the Customer's Energy and Demand as accurately as possible, the Customer may request adjustments to the CBL for the following reasons:

1. The installation of permanent energy efficiency measures either as a participant in Energy Trust of Oregon programs or other verifiable conservation or technology improvement measures.
2. The addition or removal of equipment that results in a permanent change in the Customer's expected electricity consumption.

If the Customer leaves the program, he/she may not be allowed to return for a minimum of 12 months. A new CBL will be calculated in such cases based on the most recent usage. At a minimum, the CBL will be reviewed every three years and may be adjusted.

HOURLY ENERGY PRICE

Hourly Energy Prices are determined each day for the following day using Mid-Columbia Day Ahead Prices for on- and off-peak periods shaped to hourly prices based on the reported hourly Mid-Columbia prices from preceding days. The following charges will be added to the shaped hourly prices, 0.226¢ per kWh for wheeling, plus losses and the System Usage Charge as specified in Schedule 89. If prices are not reported for a particular day or days, the Company will estimate and shape prices from its hourly Energy price projections. **(R)**

In addition to the above charges, consumption of Energy above the CBL will be billed a 0.300¢ per kWh recovery factor. For consumption of Energy below the CBL, a 0.300¢ per kWh recovery factor will be subtracted from the Hourly Energy Price.

SCHEDULE 89
LARGE NONRESIDENTIAL (>1,000kW)
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$160.00	$230.00	$1,000.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.75	$0.75	$0.75	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	
Over 1,000 kW	$0.61	$0.39	$0.39	(I)
per kW of monthly On-Peak Demand	$2.18	$2.18	$1.10	(R)
Energy Charge				
On-Peak Period***	6.865 ¢	6.618 ¢	6.519 ¢	(I)
Off-Peak Period***	5.367 ¢	5.171 ¢	5.090 ¢	(I)
See below for Daily or Monthly Pricing Option descriptions.				
System Usage Charge				
Per kWh	0.407 ¢	0.387 ¢	0.372 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 89 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTIONS

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices (R) are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Quarterly Election Enrollment Window.

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

Monthly Fixed Price Option - A monthly fixed price per kWh quoted by the Company, differentiated by on- and off-peak hours for the next calendar month. The quote will be made on the 15th of the preceding month (or the following working day if the 15th is a weekend or holiday) by a posting on the Company's website (www.PortlandGeneral.biz) and will be based on the expected market price for power delivered to the Company's service territory plus losses. The Customer will notify the Company by 5:00 p.m. PPT on the business day following such posting of its choice of this option.

Non-Cost of Service Options are subject to Schedule 128, Short Term Transition Adjustment

SCHEDULE 91 (Continued)

MAINTENANCE (Continued)

Maintenance of Option B luminaires includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance does not include replacement of a luminaire at end of life (when replacement of a part will not bring the unit into working condition and the unit is not inoperable due to damage from accident or vandalism). Option B Maintenance also does not include replacement of technologically obsolete luminaires still in working condition, or for which a simple part replacement (any combination of photocell, lamp, starter and refractor) will return obsolete lights to operable condition.

Non-Standard or Custom luminaires and poles are provided to allow greater flexibility in the choice of equipment. However, the Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. Also, this equipment is more subject to obsolescence. The Company will order and replace the equipment subject to availability.

If damage occurs to any lighting poles more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. Pole maintenance does not include painting of fiberglass, or painting or staining wood poles. It does not include testing or treating of wood poles. Maintenance of Option B poles does not include replacement of rotted wood poles that are no longer structurally sound, or any other poles which by definition have reached a natural end of life.

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each luminaire based on the Monthly kWhs applicable to each installed luminaire.

Transmission and Related Services Charge	0.127 ¢ per kWh	(I)
Distribution Charge	3.142 ¢ per kWh	
Energy Charge		
Cost of Service Option	5.857 ¢ per kWh	(I)

Daily Price Option – Available only to Customers with an average load of five MW or greater. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

SCHEDULE 91 (Continued)

MONTHLY RATE (Continued)

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily Energy Rate Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the above applicable Daily Price by 1.0834.

To begin service under this option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Cobrahead Power Doors **	100	9,500	43	*	$2.70	(R)
	150	16,000	62	*	2.71	
	200	22,000	79	*	2.76	
	250	29,000	102	*	2.73	
	400	50,000	163	*	2.74	
Cobrahead	100	9,500	43	$5.28	2.80	
	150	16,000	62	5.30	2.81	
	200	22,000	79	5.72	2.86	
	250	29,000	102	5.77	2.87	
	400	50,000	163	5.79	2.89	
Flood	250	29,000	102	6.04	2.90	
	400	50,000	163	6.06	2.92	(R)

* Not offered.
** Service is only available to Customers with total power door luminaries in excess of 2,500.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Early American Post-Top	100	9,500	43	$5.68	$2.80	(R)
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	5.90	2.88	
	100	9,500	43	6.11	2.90	
	150	16,000	62	6.38	2.93	(R)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black	20	$4.10	$0.14	
Fiberglass, Bronze	30	5.47	0.18	(I)
Fiberglass, Gray	30	5.49	0.18	(I)
Wood, Standard	30 to 35	4.71	0.15	
Wood, Standard	40 to 55	5.91	0.20	

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Acorn-Types						
HPS	100	9,500	43	$8.72	$3.21	(I)
HADCO Independence, HPS	100	9,500	43	8.01	3.09	
	150	16,000	62	8.02	3.10	
HADCO Capitol Acorn, HPS	100	9,500	43	12.29	3.58	
	150	16,000	62	12.31	3.60	
	200	22,000	79	12.31	3.60	
	250	29,000	102	12.31	3.60	
Special Architectural Types						
HADCO Victorian, HPS	150	16,000	62	8.44	3.19	
	200	22,000	79	8.49	3.20	
	250	29,000	102	8.58	3.21	(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
HADCO Techtra, HPS	100	9,500	43	$14.77	$3.85	(I)
	150	16,000	62	14.79	3.87	
	250	29,000	102	20.93	4.59	
KIM Archetype, HPS	250	29,000	102	*	3.34	
	400	50,000	163	*	3.34	(I)
HADCO Westbrooke, HPS	70	6,300	30	12.24	2.64	(R)
	100	9,500	43	12.19	2.62	
	150	16,000	62	12.20	2.63	
	200	22,000	79	12.34	2.63	
	250	29,000	102	12.36	2.65	(R)
Special Types						
Cobrahead, Metal Halide	175	12,000	71	5.50	2.95	(I)
Flood, Metal Halide	400	40,000	156	6.07	3.05	
Flood, HPS	750	105,000	285	8.41	4.00	
Holophane Mongoose, HPS	150	16,000	62	7.40	3.13	
	250	29,000	102	7.49	3.14	
	400	50,000	163	7.53	3.16	(I)

* Not offered.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, Regular	16	$5.83	$0.20	
	25	9.48	0.32	(R)
	30	10.26	0.34	
	35	11.29	0.38	
Aluminum Davit	25	9.79	0.33	
	30	10.44	0.35	
	35	11.53	0.38	
	40	14.08	0.47	
Aluminum Double Davit	30	12.56	0.42	(R)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, HADCO, Fluted Victorian Ornamental	14	$11.08	$0.37	(R)
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	19.81	0.65	
Aluminum, HADCO, Fluted Ornamental	16	10.60	0.35	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	15.95	0.52	
Aluminum, Painted Ornamental	35	27.35	0.90	
Concrete, Ameron Post-Top	25	23.42	0.78	
Fiberglass, HADCO, Fluted Ornamental Black	14	6.47	0.21	
Fiberglass, Regular				
color may vary	22	3.17	0.11	
color may vary	35	7.47	0.25	
Fiberglass, Anchor Base, Gray	35	11.95	0.40	(R)
Fiberglass, Direct Bury with Shroud	18	6.20	0.21	

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$5.37	$2.70	(R)
	250	10,000	94	6.31	2.94	
	400	21,000	147	5.48	2.82	
	1,000	55,000	374	6.28	3.13	
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	8.68	2.80	
Mercury Vapor	175	7,000	66	8.90	2.80	(R)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Box, Anodized Aluminum Similar to GardCo Hub						
HPS	Twin 70	6,300	60	*	*	
	70	6,300	30	*	*	
	100	9,500	43	$8.52	$3.17	(I)(I)
	150	16,000	62	*	3.18	(I)
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	3.35	(I)
	400	40,000	156	*	3.76	(I)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	2.80	(R)
100/150 Watt Ballast	100	9,500	43	*	2.80	|
100/150 Watt Ballast	150	16,000	62	*	2.81	(R)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	3.62	(I)
Special Acorn-Type, HPS	70	6,300	30	8.45	2.80	(R)(R)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	
Special Acrylic Sphere						
Mercury Vapor	400	21,000	147	*	*	
Early American Post-Top, HPS						
Black	70	6,300	30	5.17	2.81	(R)(R)
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.50	2.72	(R)(R)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Flood, HPS	70	6,300	30	$5.75	$2.86	(R)
	100	9,500	43	5.65	2.84	
	200	22,000	79	6.04	2.90	
Cobrahead, HPS						
Non-Power Door	70	6,300	30	5.19	2.80	
Power Door	310	37,000	124	6.47	3.21	(R)
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Flourescent	28	N/A	12	*	*	

* Not offered.

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$5.83	*	
Bronze Alloy GardCo	12	*	$0.24	
Concrete, Ornamental	35 or less	9.48	0.32	(R)
Steel, Painted Regular **	25	9.48	0.32	
Steel, Painted Regular **	30	10.26	0.34	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.34	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.35	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.38	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.38	(R)
Wood, Laminated without Mast Arm	20	5.30	0.14	
Wood, Laminated Street Light Only	20	4.10	*	

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES (Continued)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Wood, Curved Laminated	30	$6.84	$0.25	(R)
Wood, Painted Underground	35	4.71	0.20	
Wood, Painted Street Light Only	35	4.71	*	

* Not offered.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	$10.62	$2.08	(R)
	165	12,000	60	12.32	2.17	(I)
HADCO Techtra, QL	85	6,000	32	13.99	2.20	(R)
	165	12,000	60	14.72	2.26	(R)

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

During the Quarterly Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

SCHEDULE 92
TRAFFIC SIGNALS
(NO NEW SERVICE)
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments where funds for payment of Electricity are provided through taxation or property assessment for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Transmission and Related Services Charge	0.144	¢ per kWh	(I)
Distribution Charge	2.162	¢ per kWh	
Energy Charge	6.191	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

During the Quarterly Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

SCHEDULE 93
RECREATIONAL FIELD LIGHTING, PRIMARY VOLTAGE
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for recreational field lighting and related incidental lighting.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$30.00		
Transmission and Related Services Charge	0.180	¢ per kWh	(R)
Distribution Charge	9.266	¢ per kWh	(I)
Energy Charge	6.300	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge, if necessary, to justify the Company's investment in service facilities.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITION

The Customer's electrical equipment and its installation must be approved by the Company. All service under this schedule at any one location will be supplied through one meter.

TERM

Service under this schedule will not be for less than a one year.

SCHEDULE 94
COMMUNICATION DEVICES ELECTRICITY SERVICE RIDER

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments that have communication devices with energy requirements not exceeding 25 line watts per unit, that are installed on streetlights and, or traffic signals served under Schedules 91 and, or 92.

CHARACTER OF SERVICE

60-hertz alternating current of such phase and voltage as the Company may have available.

SERVICE

Service under this schedule will be based on an estimated total monthly kWh used, as determined by the Company, for all the Customer's devices. The estimated monthly usage will be updated as needed to reflect device installations or removals. Monthly kilowatt-hour usage will be computed on the basis of manufacturer's line wattage ratings of installed devices, with no allowances for outages.

MONTHLY RATE

The sum of the following charges per Point of Delivery:*

Transmission and Related Services Charge	0.144 ¢ per kWh	(I)
Distribution Charge	2.162 ¢ per kWh	(I)
Energy Charge	6.191 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments

The monthly kWh charge for service under this rider will be the number of units times estimated monthly usage determined using the following formula:

[((No. of Units x line watts per unit) x annual operating hours) / 1000] / 12

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules.

APPLICABLE ADJUSTMENT SCHEDULES

(N)

Schedules	102	105	106	107	108	115	120	122	123	125	126	128	129	130
	(1)		(1)		(3)		(1)			(1)		(4)	(1)	(1)
7	X	X	X	X	X	X	X	X	X	X	X			
9			X(1)		X	X								
15	X	X	X	X	X	X	X	X	X	X	X			
32	X	X	X	X	X	X	X	X	X	X	X	X		
38	X	X	X	X	X	X	X	X	X	X	X	X		X
47	X	X	X	X	X	X	X	X	X	X	X			
49	X	X	X	X	X	X	X	X	X	X	X			
75	X(2)	X(2)	X	X(2)	X	X	X(2)	X(2)	X	X(2)	X(2)	X		
76R	X	X	X	X	X	X			X					
83	X	X	X	X	X	X	X	X	X	X	X	X		X
87	X(2)	X(2)	X	X(2)	X	X	X(2)	X(2)	X	X	X(2)			
89	X	X	X	X	X	X	X	X	X	X	X	X		X
91		X	X	X	X	X	X	X	X	X	X	X		
92		X	X	X	X	X	X	X	X	X	X			
93		X	X	X	X	X	X	X	X	X	X			
94		X	X	X	X	X	X	X	X	X	X			
483	X	X	X	X	X	X			X		X(5)		X	
489	X	X	X	X	X	X			X		X(5)		X	
515	X	X	X	X	X	X		X	X		X(5)	X		
532	X	X	X	X	X	X		X	X		X(5)	X		
538	X	X	X	X	X	X		X	X		X(5)	X		X
549	X	X	X	X	X	X		X	X		X(5)	X		
575	X(2)	X(2)	X	X(2)	X	X		X(2)	X		X(2)	X		
576R	X	X	X	X	X	X			X					
583	X	X	X	X	X	X		X	X		X(5)	X		X
589	X	X	X	X	X	X		X	X		X(5)	X		X
591		X	X	X	X	X		X	X		X(5)	X		
592		X	X	X	X	X		X	X		X(5)	X		
594		X	X	X	X	X		X	X		X	X		

(N)

(1) Where applicable.
(2) These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Schedule 108 applies to the sum of all charges less taxes, Schedule 115 charges and one-time charges such as deposits.
(4) Applicable to Nonresidential Customer who receive service at Daily or Monthly pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 483 and 489).
(5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 120
BIGLOW CANYON I ADJUSTMENT

PURPOSE

This schedule recovers the net costs of the Company's Biglow Canyon I wind project. Approval of this tariff adjustment will be considered a Commission revision of the Company's ratio of net revenues to gross revenues and effective tax rate for purposes of OAR 860-22-0041.

AVAILABLE

In all territory served by the Company

APPLICABLE

To all bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 87, 89, 91, 92, 93 and 94.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after January 1, 2009, are: (C)

Schedule	Adjustment Rate	
7	0.000 ¢ per kWh	(R)
15	0.000 ¢ per kWh	
32	0.000 ¢ per kWh	
38	0.000 ¢ per kWh	
47	0.000 ¢ per kWh	
49	0.000 ¢ per kWh	
75		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
83		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
87		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
89		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	(R)

SCHEDULE 120 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
91	0.000 ¢ per kWh	(R)
92	0.000 ¢ per kWh	
93	0.000 ¢ per kWh	(R)
94	0.000 ¢ per kWh	

SPECIAL CONDITIONS

1. Rates under this schedule will recover the net costs of Biglow Canyon I from all applicable customers on an equal cents per kWh basis adjusted for delivery voltage.

2. The rates contained in this schedule will, if necessary, be revised and refiled on November 15, 2007 to be consistent with the load forecast and forward price curves used in the Annual Power Cost Update also filed on that date. The rates in this schedule will be added to the applicable rate schedules' Cost of Service Energy Charges for purposes of calculating the Schedule 128, Short-Term Transition Adjustment.

3. If the Biglow Canyon I wind project is not expected to achieve commercial operation by January 1, 2008, the Company will notify the Commission by December 31, 2007. In such case, the effective date of the above adjustment rates will be delayed until one day after the Company notifies the Commission that the project has achieved commercial operation.

4. Any power produced by Biglow Canyon 1 prior to January 1, 2008 will be valued for power cost purposes at the monthly average of the daily Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) for determining actual NVPC under Schedule 126, Annual Power Cost Variance Mechanism.

5. The Biglow Canyon 1 revenue requirements recovered under this schedule that are not otherwise recovered through Schedule 125 will be updated annually and will continue to be recovered under this Schedule 120 until such costs are included in base rates. Beginning in 2008, if the Company has not filed a general rate case by April 1 of any year, the Company will file by April 1 proposed updates to this schedule and the revenue requirement update process will be on the same schedule as updates to Schedule 125. The annual update will include updates to gross revenues, net revenues, and total income tax expense for the calculation of "taxes authorized to be collected in rates" pursuant to OAR 860-022-0041.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 123
SALES NORMALIZATION ADJUSTMENT

PURPOSE

This Schedule establishes a balancing account and rate adjustment mechanism to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Point of Delivery during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

> **Energy Efficiency Measures (EEMs)** – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.
>
> **Self-Directing Customer (SDC)** - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, for Customers served under Schedules 7, 32 and 532, differences between a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) of 5.082 cents/kWh for Schedule 7 and 4.625 cents/kWh for Schedules 32 and 532 to weather-normalized kWh Energy sales, and 2) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer of $45.59 per month for Schedule 7 and $69.10 per month for Schedules 32 and 532 to the number of active Schedule 7 and Schedule 32 and 532 Customers respectively for each month.

The SNA will calculate monthly as the Fixed Charge Revenue less actual weather-adjusted revenues and will accrue to the SNA Balancing Account. Such monthly amount which may be positive (an undercollection) or negative (an overcollection) will accrue to the Sales Normalization Balancing Account.

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532 or otherwise as exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during the prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates.

Lost Revenue Recovery may be positive or negative. Negative Lost Revenue Recovery will occur if actual kWh savings are less than estimated in setting base rates.

For the purposes of this Schedule, Lost Revenue Recovery is the product of the reduction in kWh sales resulting from ETO-reported EEMs and the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule weighted average of transmission, distribution, and fixed generation charges including those contained in Schedules 120 and 122. Schedules 32 and 532 are not included in the weighted average base rate calculation. System usage charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. As of the effective date of this schedule, the applicable Lost Revenue Rate is 3.520 ¢ per kWh.

SALES NORMALIZATION ADJUSTMENT AND LOST REVENUE BALANCING ACCOUNT

The Company will maintain a separate balancing account for the SNA, applicable to Schedules 7, 32 and 532 and for the Nonresidential Lost Revenue Recovery for the remaining applicable nonresidential Schedules. The balancing accounts will record over- and under-collections resulting from differences as determined by the SNA and Lost Revenue Recovery mechanisms. The accounts will accrue interest at the Company's authorized rate of return.

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA)

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
15	0.000 ¢ per kWh
32	0.000 ¢ per kWh
38	0.000 ¢ per kWh
47	0.000 ¢ per kWh
49	0.000 ¢ per kWh
75	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
76R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
83	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
87	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
89	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
91	0.000 ¢ per kWh
92	0.000 ¢ per kWh
93	0.000 ¢ per kWh
94	0.000 ¢ per kWh

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

Schedule	Adjustment Rate
483	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
489	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
515	0.000 ¢ per kWh
532	0.000 ¢ per kWh
538	0.000 ¢ per kWh
549	0.000 ¢ per kWh
575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
576R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
583	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
589	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
591	0.000 ¢ per kWh
592	0.000 ¢ per kWh
594	0.000 ¢ per kWh

SCHEDULE 123 (Concluded)

TIME AND MANNER OF FILING

Commencing in 2010, the Company will submit to the Commission the following information by April 1 of each year:

1. The proposed price changes to this Schedule to be effective on June 1st of the submittal year based on a) the amount in the SNA Balancing Account at the end of the previous calendar year, and b) the amount in the Lost Revenue Recovery Balancing Account amount at the end of the previous calendar year.

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers.

3. The status of the SNA and Lost Revenue Balancing Accounts.

SPECIAL CONDITIONS

1. The Fixed Charge Energy Rate, Monthly Fixed Charge per Customer Rate and the Lost Revenue Rate will be updated concurrently with a change in the applicable base revenues used to determine the charge.

2. Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that determination of forecasted loads used to set rates.

3. No revision to the Sales Normalization Adjustment Rates will result in an estimated average annual rate increase greater than 2% to the applicable SNA rate schedules or to the applicable Lost Revenue Recovery rate schedules based on the net rates in effect on the effective date of the rate revision under this schedule. Any remaining amounts in the Balancing Accounts will be included in subsequent revisions to the Sales Normalization Rates. Rate revisions resulting in a rate decrease are not subject to the 2% limit.

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs. This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 87, 89, 91, 92, 93 and 94.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs. (C)
- No other changes or updates will be made in the annual filings under this schedule.

ADJUSTED NET VARIABLE POWER COSTS (T)

Adjusted Net Variable Power Costs for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update plus changes in fixed generation revenues caused by the change in Cost of Service loads resulting from either return to or departures from Cost of Service pricing by Schedule 483 and 489 customers relative to the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0342. (C)

(C)(I)

SCHEDULE 125 (Continued)

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final unit change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine the Annual Power Cost Update. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices. (C)

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh	
7		0.000	(I)
15		0.000	
32		0.000	
38	Large Nonresidential	0.000	
47		0.000	
49		0.000	
75	Secondary	0.000 (1)	
	Primary	0.000 (1)	
	Subtransmission	0.000 (1)	
83	Secondary	0.000	
	Primary	0.000	
87	Secondary	0.000	
	Primary	0.000	
	Subtransmission	0.000	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh	
89	Secondary	0.000	(I)
	Primary	0.000	
	Subtransmission	0.000	
91		0.000	
92		0.000	
93		0.000	
94		0.000	(I)

SPECIAL CONDITIONS (N)

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

2. In determining changes in fixed generation revenues from movement to or from Schedules 483 and 489, the following factors will be used:

Schedule		¢ per kWh	
83	Secondary	1.942	
	Primary	1.879	
89	Secondary	1.950	
	Primary	1.860	
	Subtransmission	1.818	(N)

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those served on Schedule 76R and 576R, and those served on Schedules 483, 489, 515, 532, 538, 549, 583, 589, 591, 592 and 594, where service under these schedules was received for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 589, 591 and 592 who receive the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE (PVC)

Subject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual Variance amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. Interest will accrue on the account at the Company's authorized rate of return. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest on the PCV Account calculated at the Company's authorized cost of capital. This amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0342 (I)
to account for franchise fees, uncollectibles, and OPUC fees. (T)

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount to the extent that such refunding will not cause the Company's Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

Schedule 126 (Continued)

DEFINITIONS (Continued)

Net Variable Power Costs (NVPC)

The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission / wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 38, 83, 89, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 483 and 489 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0342 to account for franchise fees, uncollectables, and (T)(I)
OPUC fees. (T)

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily or Monthly pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 89 or 91; or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 589, 591, 592, 594. This Schedule is not applicable to Customers served on Schedules 483 and 489.

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service for 2008, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2008:

Schedule		Annual ¢ per kWh (1)	
32		(0.891)	(I)
38		(0.889)	
75	Secondary On-Peak	(0.962) (2)	
	Secondary Off-Peak	(0.753) (2)	
	Primary On-Peak	(0.928) (2)	
	Primary Off-Peak	(0.726) (2)	
	Subtransmission On-Peak	(0.914) (2)	
	Subtransmission Off-Peak	(0.714) (2)	
83	Secondary	(0.885)	
	Primary	(0.857)	(I)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh [(1)]	
89	Secondary On-Peak	(0.962)	(I)
	Secondary Off-Peak	(0.753)	
	Primary On-Peak	(0.928)	
	Primary Off-Peak	(0.726)	
	Subtransmission On-Peak	(0.914)	
	Subtransmission Off-Peak	(0.714)	
91		(0.822)	
515		(0.822)	
532		(0.891)	
538		(0.889)	
549		(0.858)	
575	Secondary On-Peak	(0.962) [(2)]	
	Secondary Off-Peak	(0.753) [(2)]	
	Primary On-Peak	(0.928) [(2)]	
	Primary Off-Peak	(0.726) [(2)]	
	Subtransmission On-Peak	(0.914) [(2)]	
	Subtransmission Off-Peak	(0.714) [(2)]	
583	Secondary	(0.885)	
	Primary	(0.857)	
589	Secondary On-Peak	(0.962)	
	Secondary Off-Peak	(0.753)	
	Primary On-Peak	(0.928)	
	Primary Off-Peak	(0.726)	
	Subtransmission On-Peak	(0.914)	
	Subtransmission Off-Peak	(0.714)	
591		(0.822)	
592		(0.868)	
594		(0.868)	(I)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term Transition Adjustment rate will be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. Indicative, non-binding estimates for the Annual Short-Term Transition Adjustment will be posted by the Company two months and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

SCHEDULE 128 (Continued)

LARGE NONRESIDENTIAL LOAD SHIFT TRUE-UP

For the November window, the Company will compute the Load Shift True-Up as the difference between the market prices used to establish the Schedule 128 Transition Adjustment and the average of the corresponding projected market prices during the first full week in December times the load leaving Cost of Service pricing. For the Balance of Year Transition Adjustment windows, the Company will compute the True-Up as the difference between the market prices used to establish the Schedule 128 Transition Adjustments and the corresponding projected market prices during the first full week after the close of the window times the amount of load leaving Cost of Service pricing. For the November election window, the Company will file for a deferral after the close of the window if the True-Up is greater than $240,000. The filing threshold for each of the quarterly windows will be $60,000. (C)

(C)

BALANCING ACCOUNT

The Company will maintain a Balancing Account to accrue any deferred load shift true-up amounts. The Balancing Account will accrue interest at the Company's authorized cost of capital. These monies will be recovered from or refunded to all direct-access eligible Large Nonresidential Customers in a manner approved by the Commission.

CHANGES TO TRANSITION ADJUSTMENT RATES

The Short-Term Transition Adjustment is subject to modification to reflect any changes to the Energy Charge(s) of the Cost of Service Option that serve as the basis for the calculation of the Transition Adjustment. No change will be made, however, to the market price of power used to determine the applicable adjustment rate.

BALANCE-OF-YEAR TRANSITION ADJUSTMENT RATE

Eligible customers who have elected to receive service on a rate other than Cost of Service during a Quarterly Enrollment Window, will have the applicable Short-Term Balance-of-Year Transition Adjustment Rate applied to their bills.

The Balance-of-Year Transition Adjustment Rate will be filed, posted on the Company's website and incorporated into this Schedule effective as follows:

- February 15th for an April 1st effective date
- May 15th for a July 1st effective date
- August 15th for an October 1st effective date

Where the date above is a weekend or state-recognized holiday, the filing date will be the next business day. The Short-Term Balance-of-Year Transition Adjustment will be posted by the Company on its website (www.PortlandGeneral.biz) on the day the rate is filed with the Commission.

SCHEDULE 129 (Concluded)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out

For Enrollment Period F (2007), the Transition Cost Adjustment will be:

(1.250) ¢ per kWh	January 1, 2008 through December 31, 2008
(1.434) ¢ per kWh	January 1, 2009 through December 31, 2009
(1.248) ¢ per kWh	January 1, 2010 through December 31, 2010

SPECIAL CONDITION

Annually, the total amount paid in Schedule 129 Long-Term Transition Cost Adjustment will be collected through applicable Large Nonresidential rate schedules (Schedules 75, 76R, 83, 89, 483, (C)
489, 575, 576R, 583, 589), through either the System Usage or Distribution Charges. Such (C)
adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedule 483 or 489.

SCHEDULE 300
CHARGES AS DEFINED BY THE RULES AND REGULATIONS AND MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to list the charges referred to in the General Rules and Regulations.

AVAILABLE

In all territory served by the Company.

APPLICABLE

For all Customers utilizing the services of the Company as defined and described in the General Rules and Regulations.

INTEREST ACCRUED ON DEPOSITS (See Rules D and H)

4% per annum.

BILLING RATES (Rules C, E, F, H, I and J)

Trouble call, cause in Customer-owned equipment

Scheduled Crew Hours (1)	No charge	
Other than Scheduled Crew Hours (1)	$170.00	
Returned Payment Charge	$ 25.00	
Special Meter Reading Charge	$ 35.00	
Meter Test Charge	$ 75.00	
Late Payment Charge	1.7% of delinquent balance	
Field Visit Charge (2)	$ 45.00	(I)
Bill History Information Service Charge (Not applicable when a billing dispute is filed with the Commission - see Rule F)	$ 32.00	
Portfolio Enrollment Charge	$ 5.00	
Customer Interval Data (12 months) to Customers	$100.00	
Customer Interval Data (12 months, formatted and analyzed)	Mutually agreed price	
Switching Fee	$20.00	
Unauthorized Connection of Service / Tamper Fee	$75.00	

(1) Scheduled Crew Hours - The Company's Scheduled Crew Hours for the above listed services are from 6:30 a.m. to 10:30 p.m., Monday through Friday, except for Company-recognized holidays. The Customer will be informed of and agree to the charges before Company personnel are dispatched.

(2) See Rule H, Section 2 for applicable conditions.

SCHEDULE 300 (Continued)

CREDIT RELATED DISCONNECTION AND RECONNECTION RATES (Rule H)

Disconnects		
Monday through Friday	No charge	
Reconnection		
Standard Reconnection		
At Meter Base	$ 45.00	(I)
Other than Meter Base	$ 210.00	(I)
After Hours Reconnection(1)		
At Meter Base	$ 80.00	
Other than Meter Base	$ 575.00	(I)

CUSTOMER REQUESTED DISCONNECTION AND RECONNECTION RATES (Rule H)(2)(3)

Disconnects		
Standard		
At Meter Base	No charge	
Other than Meter Base	No charge	
After Hours		
Non-safety related		
At Meter Base	$ 325.00	(I)
Other than Meter Base	$ 575.00	(I)
Reconnects		
Standard		
Safety related	No charge	
Non-safety related		
At Meter Base	$ 45.00	(I)
Other than Meter Base	$ 210.00	(I)
After Hours		
At Meter Base	$ 325.00	(I)
Other than Meter Base	$ 575.00	(I)

(1) PGE representatives will be dispatched to reconnect service until 7:00 p.m., Monday through Friday. As such, crews dispatch up to and including 7:00 p.m. may be reconnecting service after 7:00 p.m. State- and utility-recognized holidays are excluded from the after hours provision.

(2) These rates apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In other cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.

(3) No charge for disconnects / reconnects completed to ensure safe working conditions that meet the guidelines in Rule H(4).

SCHEDULE 483 (Continued)

ENROLLMENT PERIODS (Continued)

Fixed Three-Year Option (Continued)

Enrollment Period C: Applicable to any Customer who enrolled between September 1 and September 30, 2004, with a service period from January 1, 2005 through December 31, 2007.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

Enrollment Period F: Applicable to any Customer who enrolled between September 1, 2007 and September 30, 2007, with a service period from January 1, 2008 through December 31, 2010.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

MONTHLY RATE

The monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge			
Single Phase Service	$20.00		(T)
Three Phase Service	$25.00	$80.00	(T)(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 30 kW	$1.54	$1.81	(R)
Over 30 kW	$2.34	$1.81	(I)(N)
per kW of monthly Demand	$2.13	$2.13	(I)(R) (D)
System Usage Charge			
per kWh	0.419 ¢	0.403 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 483 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.529 per kW of monthly Demand. **(R)**

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

SCHEDULE 489 (Continued)

ENROLLMENT PERIODS (Continued)

Fixed Three-Year Option (Continued)

Enrollment Period C: Applicable to any Customer who enrolled between September 1 and September 30, 2004, with a service period from January 1, 2005 through December 31, 2007.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

Enrollment Period F: Applicable to any Customer who enrolled between September 1, 2007 and September 30, 2007, with a service period from January 1, 2008 through December 31, 2010.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$160.00	$230.00	$1,000.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	(I)
Over 1,000 kW	$0.61	$0.39	$0.39	(I)
per kW of monthly On-Peak Demand	$2.18	$2.18	$1.10	(R)
System Usage Charge				
per kWh	0.407 ¢	0.387 ¢	0.372 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.529 per kW of monthly Demand. (R)

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

SCHEDULE 515
OUTDOOR AREA LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Nonresidential Customers purchasing Direct Access Service for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer or Electricity Service Supplier (ESS) notifies the Company of the burn-out.

MONTHLY RATE

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$7.74 [2]	(R)
	400	21,000	147	10.38 [2]	
	1,000	55,000	374	18.33 [2]	
HPS	70	6,300	30	6.41 [2]	
	100	9,500	43	6.90	
	150	16,000	62	7.53	
	200	22,000	79	8.52	
	250	29,000	102	9.29	
	310	37,000	124	10.71 [2]	
	400	50,000	163	11.22	(R)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Flood , HPS	100	9,500	43	$7.31 [2]	(R)
	200	22,000	79	8.61 [2]	
	250	29,000	102	9.60	
	400	50,000	163	11.52	(R)
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	7.27	(N)
	100	9,500	43	7.82	(R)
	150	16,500	62	8.72	(R)
Special Acorn Type, HPS	100	9,500	43	10.70	(I)
HADCO Victorian, HPS	150	16,500	62	10.99	
	200	22,000	79	11.57	(I)
	250	29,000	102	12.39	(R)
Early American Post-Top, HPS, Black	100	9,500	43	7.78	
Special Types					
Cobrahead, Metal Halide	175	12,000	71	8.02	
Flood, Metal Halide	400	40,000	156	11.29	
Flood, HPS	750	105,000	285	17.82	
HADCO Independence, HPS	100	9,500	43	9.92	
	150	16,000	62	10.53	(R)
HADCO Capitol Acorn, HPS	100	9,500	43	14.63	(I)
	150	16,000	62	15.25	
	200	22,000	79	15.78	
	250	29,000	102	16.50	
HADCO Techtra, HPS	100	9,500	43	17.38	
	150	16,000	62	18.00	
	250	29,000	102	26.01	(I)
KIM Archetype, HPS	250	29,000	102	13.85	
	400	50,000	163	15.57	(R)
Holophane Mongoose, HPS	150	16,000	62	9.84	
	250	29,000	102	11.18	
	400	40,000	163	13.12	(R)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$5.98	
	55 or less	7.51	
Wood, Painted Underground	35 or less	6.99 [2]	
Wood, Curved laminated	30 or less	8.68 [2]	(I)
Aluminum, Regular	16	7.40	
	25	12.03	(I)
	30	13.03	
	35	14.33	
Aluminum, Fluted Ornamental	14	14.07	
Aluminum Davit	25	12.43	
	30	13.25	
	35	14.65	
	40	17.88	
Aluminum Double Davit	30	15.95	
Aluminum, HADCO, Fluted Ornamental	16	13.47	
Aluminum, HADCO, Non-fluted	18	25.16	
Concrete, Ameron Post-Top	25	29.74	
Fiberglass Fluted Ornamental; Black	14	8.22	(I)
Fiberglass, Regular			
Black,	20	5.20	
Gray or Bronze;	30	6.97	(I)
Other Colors (as available)	35	9.48	
Fiberglass, Anchor Base Gray	35	15.17	(I)
Fiberglass, Direct Bury with Shroud	18	7.87	

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase	$14.35	
Three Phase	$20.25	
Distribution Charge		
First 5,000 kWh	2.987 ¢ per kWh	(I)
Over 5,000 kWh	0.576 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00		
Distribution Charge	3.875	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Summer Months**	$30.00	
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	3.276 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	1.276 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply all or some portion of their load by self generation operating on a regular basis, where the self-generation has a total nameplate rating of 1 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$160.00	$230.00	$1,000.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	(I)
Over 1,000 kW	$0.61	$0.39	$0.39	(I)
per kW of monthly On-Peak Demand**	$2.18	$2.18	$1.10	(R)
Generation Contingency Reserves Charges***				
Spinning Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.407 ¢	0.387 ¢	0.372 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Delivery Voltage		
	Secondary and Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge			
per kW of Daily ERP Demand during On-Peak hours per day**	$0.085	$0.043	(R)
System Usage Charge			
per kWh of ERP		0.372 ¢	(I)
Transaction Fee			
per Energy Needs Forecast (ENF) submission or revision		$50.00	

* See Schedule 100 for applicable adjustments.

** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has not exceeded 1,000 kW more than once in the proceeding 13 months and who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00	$80.00	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 30 kW	$1.54	$1.81	(R)
Over 30 kW	$2.34	$1.81	(I)(N)
per kW of monthly Demand	$2.13	$2.13	(I)(R) (D)
System Usage Charge			
per kWh	0.419 ¢	0.403 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 589
LARGE NONRESIDENTIAL
(>1000 kW)
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 kW, and who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$160.00	$230.00	$1,000.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	(I)
Over 1,000 kW	$0.61	$0.39	$0.39	(I)
per kW of monthly on-peak Demand	$2.18	$2.18	$1.10	(R)
System Usage Charge				
per kWh	0.407 ¢	0.387 ¢	0.372 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 591 (Continued)

MAINTENANCE (Continued)

Maintenance of Option B luminaires includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance does not include replacement of a luminaire at end of life (when replacement of a part will not bring the unit into working condition and the unit is not inoperable due to damage from accident or vandalism). Option B Maintenance also does not include replacement of technologically obsolete luminaires still in working condition, or for which a simple part replacement (any combination of photocell, lamp, starter and refractor) will return obsolete lights to operable condition.

Non-Standard or Custom luminaires and poles are provided to allow greater flexibility in the choice of equipment. However, the Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. Also, this equipment is more subject to obsolescence. The Company will order and replace the equipment subject to availability.

If damage occurs to any lighting poles more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. Pole maintenance does not include painting of fiberglass, or painting or staining wood poles. It does not include testing or treating of wood poles. Maintenance of Option B poles does not include replacement of rotted wood poles that are no longer structurally sound, or any other poles which by definition have reached a natural end of life.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each luminaire based on the Monthly kWhs applicable to each installed luminaire.

Distribution Charge	3.142 ¢ per kWh	**(I)**
Energy Charge	Provided by Energy Service Supplier	

SCHEDULE 591 (Continued)

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead Power Doors **	100	9,500	43	*	$4.05	$1.35	(R)(I)
	150	16,000	62	*	4.66	1.95	
	200	22,000	79	*	5.24	2.48	
	250	29,000	102	*	5.93	3.20	
	400	50,000	163	*	7.86	5.12	
Cobrahead	100	9,500	43	$6.63	4.15	1.35	
	150	16,000	62	7.25	4.76	1.95	
	200	22,000	79	8.20	5.34	2.48	
	250	29,000	102	8.97	6.07	3.20	(R)
	400	50,000	163	10.91	8.01	5.12	
Flood	250	29,000	102	9.24	6.10	3.20	
	400	50,000	163	11.18	8.04	5.12	
Early American Post-Top	100	9,500	43	7.03	4.15	1.35	(R)
Shoebox (Bronze color, flat	70	6,300	30	6.84	3.82	0.94	
Lens, or drop lens, multi-volt)	100	9,500	43	7.46	4.25	1.35	(R)
	150	16,000	62	8.33	4.88	1.95	(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black	20	$4.10	$0.14	
Fiberglass, Bronze	30	5.47	0.18	(R)
Fiberglass, Gray	30	5.49	0.18	(R)
Wood, Standard	30 to 35	4.71	0.15	
Wood, Standard	40 to 55	5.91	0.20	

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Types							
HPS	100	9,500	43	$10.07	$4.56	$1.35	(I)
HADCO Independence, HPS	100	9,500	43	9.36	4.44	1.35	
	150	16,000	62	9.97	5.05	1.95	
HADCO Capitol Acorn, HPS	100	9,500	43	13.64	4.93	1.35	
	150	16,000	62	14.26	5.55	1.95	
	200	22,000	79	14.79	6.08	2.48	
	250	29,000	102	15.51	6.80	3.20	
Special Architectural Types							
HADCO Victorian, HPS	150	16,000	62	10.39	5.14	1.95	
	200	22,000	79	10.97	5.68	2.48	
	250	29,000	102	11.78	6.41	3.20	
HADCO Techtra, HPS	100	9,500	43	16.12	5.20	1.35	
	150	16,000	62	16.74	5.82	1.95	
	250	29,000	102	24.13	7.79	3.20	
KIM Archetype, HPS	250	29,000	102	*	6.54	3.20	
	400	50,000	163	*	8.46	5.12	
HADCO Westbrooke, HPS	70	6,300	30	13.18	3.58	0.94	(R)
	100	9,500	43	12.16	2.59	1.35	
	150	16,000	62	12.77	3.20	1.95	
	200	22,000	79	13.44	3.73	2.48	
	250	29,000	102	14.18	4.47	3.20	(R)
Special Types							
Cobrahead, Metal Halide	175	12,000	71	7.73	5.18	2.23	
Flood, Metal Halide	400	40,000	156	10.97	7.95	4.90	
Flood, HPS	750	105,000	285	17.36	12.95	8.95	
Holophane Mongoose, HPS	150	16,000	62	9.35	5.08	1.95	
	250	29,000	102	10.69	6.34	3.20	
	400	50,000	163	12.65	8.28	5.12	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, Regular	16	$5.83	$0.20	
	25	9.48	0.32	(R)
	30	10.26	0.34	
	35	11.25	0.38	
Aluminum Davit	25	9.79	0.33	
	30	10.44	0.35	
	35	11.53	0.38	
	40	14.08	0.47	
Aluminum Double Davit	30	12.56	0.42	
Aluminum, HADCO, Fluted Victorian Ornamental	14	11.08	0.37	
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	19.81	0.65	
Aluminum, HADCO, Fluted Ornamental	16	10.60	0.35	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	15.95	0.52	
Aluminum, Painted Ornamental	35	27.35	0.90	
Concrete, Ameron Post-Top	25	23.42	0.78	
Fiberglass, HADCO, Fluted Ornamental Black	14	6.47	0.21	(R)
Fiberglass, Regular,				
color may vary	22	3.17	0.11	
color may vary	35	7.47	0.25	(R)
Fiberglass, Anchor Base, Gray	35	11.95	0.40	(R)
Fiberglass, Direct Bury with Shroud	18	6.20	0.21	

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$1.23	(I)
	175	7,000	66	$7.44	$4.77	2.07	(R)
	250	10,000	94	9.26	5.89	2.95	
	400	21,000	147	10.10	7.44	4.62	
	1,000	55,000	374	18.03	14.88	11.75	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	9.62	3.74	0.94	(R)
Mercury Vapor	175	7,000	66	10.97	4.87	2.07	(R)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	1.89	
	70	6,300	30	*	*	0.94	
	100	9,500	43	9.87	4.52	1.35	
	150	16,000	62	*	5.13	1.95	
	250	29,000	102	*	*	3.20	
	400	50,000	163	*	*	5.12	
Metal Halide	250	20,500	99	*	6.46	3.11	
	400	40,000	156	*	8.66	4.90	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	4.15	1.35	(R)
100/150 Watt Ballast	100	9,500	43	*	4.15	1.35	
100/150 Watt Ballast	150	16,000	62	*	4.76	1.95	(R)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.57	1.95	(I)

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$9.39	$3.74	$0.94	(R)(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	0.94	
Mercury Vapor	175	7,000	66	*	*	2.07	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	4.62	
Early American Post-Top, HPS							
Black	70	6,300	30	6.11	3.75	0.94	
Rectangle Type	200	22,000	79	*	*	2.48	
Incandescent	92	1,000	31	*	*	0.97	
	182	2,500	62	*	*	1.95	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	7.57	4.79	2.07	
Flood, HPS	70	6,300	30	6.69	3.80	0.94	
	100	9,500	43	7.00	4.19	1.35	
	200	22,000	79	8.52	5.38	2.48	
Cobrahead, HPS							
Non-Power Door	70	6,300	30	6.13	3.74	0.94	
Power Door	310	37,000	124	10.37	7.11	3.90	(R)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	1.35	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	2.70	
Compact Fluorescent	28	N/A	12	*	*	0.38	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$5.83	*	
Bronze Alloy GardCo	12	*	$0.24	
Concrete, Ornamental	35 or less	9.48	0.32	(R)
Steel, Painted Regular **	25	9.48	0.32	
Steel, Painted Regular **	30	10.26	0.34	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.34	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.35	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.38	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.38	(R)
Wood, Laminated without Mast Arm	20	5.30	0.14	
Wood, Laminated Street Light Only	20	4.10	*	
Wood, Curved Laminated	30	6.84	0.25	(R)
Wood, Painted Underground	35	4.71	0.20	
Wood, Painted Street Light Only	35	4.71	*	

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	$11.63	$3.09	$1.01	(R)(I)
	165	12,000	60	14.21	4.06	1.89	
HADCO Techtra, QL	85	6,000	32	15.00	3.21	1.01	
	165	12,000	60	16.61	4.15	1.89	(I)

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Point of Delivery (POD)* is:

Distribution Charge	2.162 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 594
COMMUNICATION DEVICES ELECTRICITY SERVICE RIDER
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments that have communication devices with energy requirements not exceeding 25 line watts per unit, that are installed on streetlights and, or traffic signals served under Schedules 91 and, or 92.

CHARACTER OF SERVICE

60-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE*

The charge per Point of Delivery is:*

Distribution Charge	2.162 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments

The monthly kWh charge for service under this rider will be the number of units times estimated monthly usage determined using the following formula:

[((No. of Units x line watts per unit) x annual operating hours) / 1000] / 12

Where:

1) Annual operating hours are 8760
2) Line watts are based on the electrical data provided in the manufacturer's product specifications using the following criteria:

   [(110 nominal volts x rated amps) x percentage of operational rating]

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 715
ELECTRICAL EQUIPMENT SERVICES

PURPOSE

To provide construction and maintenance to Customer or utility owned electrical equipment (other than equipment owned by the Company).

AVAILABLE

In the State of Oregon.

APPLICABLE

To all Nonresidential Customers and utilities.

CHARACTER OF SERVICE

The Company provides engineering, electrical design and construction, equipment maintenance and repair, preventative diagnostic and prevention maintenance, electrical oil containment and compliance with the Environmental Protection Agency's Spill Prevention Control and Countermeasure Oil Program (SPCC), equipment leasing, Energy recovery and revenue protection and electrical equipment refurbishing and disposal services.

BILLING RATES

Service will be contractually negotiated.

SPECIAL CONDITIONS

(D)

1. Electrical Equipment Services will be provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 806-038-0640. (T)

2. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other electrical equipment services providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Electrical Equipment Services. (T)

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE ___

MOTION FOR APPROVAL OF PROTECTIVE ORDER

OF

PORTLAND GENERAL ELECTRIC COMPANY

February 27, 2008

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE _____

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by PORTLAND GENERAL ELECTRIC COMPANY	**MOTION FOR APPROVAL OF PROTECTIVE ORDER** **[EXPEDITED CONSIDERATION REQUESTED]**

Pursuant to ORCP 36(C)(7) and OAR 860-12-0035(1)(k), Portland General Electric Company ("PGE") requests the issuance of a Protective Order in this proceeding. PGE believes good cause exists for the issuance of such an order to protect confidential market information and confidential business information, plans and strategies. In support of this Motion, PGE states:

1. Concurrent with the filing of this Motion, PGE has filed a general rate case.

2. Some of the work papers supporting the rate case filing contain confidential information regarding PGE's natural gas, electric and coal market activities as well as other confidential business matters. This information will include proprietary modeling code, PGE's timing of and expected prices for electricity purchases, PGE's timing of and expected prices for natural gas purchases, PGE's forward position for electricity, PGE's forward position for natural gas, and whether and the amount by which PGE is long or short for electricity and natural gas during various periods in 2008 and 2009. This information is confidential commercial information and/or trade secrets under ORCP 36(C)(7).

3. PGE would like to file with the Commission a complete set of work papers as soon as possible, and requests expedited consideration of this motion.

4. PGE also anticipates that parties participating in this docket will make further requests for confidential information. PGE further anticipates it will be required to file periodic updates containing confidential information in this proceeding.

5. While PGE desires to provide parties with requested information, the information is of significant commercial value, and its public disclosure could be detrimental to PGE and its customers. The information discloses PGE's position, strategy and future needs to purchase and sell electricity, natural gas and coal. If other parties involved in the wholesale electricity, natural gas and coal markets obtained this information, they could use it to the financial harm of PGE and its customers.

6. The Commission should therefore issue a Protective Order to protect the confidentiality of that material. The requested order, identical to the one that the Commission customarily issues, is attached.

For the reasons stated above, PGE requests that a protective order be issued in this proceeding.

DATED this 27th day of February, 2008.

Respectfully submitted,

Douglas C. Tingey, OSB No. 044366
Assistant General Counsel
Portland General Electric Company
121 SW Salmon Street, 1WTC1301
Portland, Oregon 97204
(503) 464-8926 phone
(503) 464-2200 fax
doug.tingey@pgn.com

ORDER NO.

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE _____

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by PORTLAND GENERAL ELECTRIC COMPANY	**ORDER**

DISPOSITION: MOTION FOR PROTECTIVE ORDER GRANTED

On February 27, 2008, Portland General Electric Company ("PGE") filed a Motion for a Protective Order with the Public Utility Commission of Oregon ("Commission"). PGE states that good cause exists for the issuance of such an order to protect confidential business information, plans and strategies. Specifically, PGE states that the workpapers to be filed with its general rate case testimony in this docket will include confidential information such as its proprietary modeling code, timing of and expected prices for electricity and natural gas purchases, and its forward position for electricity and natural gas, along with other confidential information. PGE adds that the public release of such information could prejudice PGE and its customers.

Pursuant to OAR 860-012-0035(1)(k), I find that good cause exists to issue a Protective Order, attached as Appendix A. Under the terms of the order, a party may designate as confidential any information that falls within the scope of ORCP 36(C)(7).

Confidential information shall be disclosed only to a "qualified person" as defined in paragraph 3 of the Protective Order. Authors of the confidential material, the Commission or its Staff, and counsel of record for a party or persons directly employed by counsel are "qualified persons" who may review confidential information. Other persons desiring confidential information must become qualified pursuant to paragraph 10.

To receive confidential information, however, all parties—with the general exception of Staff—must sign the Consent to be Bound Form attached as Appendix B. This includes the party seeking the issuance of the protective order, because any party may designate information as confidential under this order.

The confidentiality of confidential information shall be preserved for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality.

All persons who are given access to confidential information have the duty to monitor their own conduct to ensure their compliance with the Protective Order. Such persons shall not use or disclose the information for any purpose other than the preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the confidential information secure. If any questions exist as to the status of any person to receive confidential information, the parties may contact the Administrative Hearings Division at (503) 378-6678.

ORDER

IT IS ORDERED that the Protective Order, attached as Appendix A, shall govern the disclosure of confidential information in this case.

Made, entered, and effective on ______________________________.

____

[Judge]
Administrative Law Judge

A party may appeal this order to the Commission pursuant to OAR 860-014-0091.

PROTECTIVE ORDER

DOCKET NO. UE ___

Scope of this Order-

1. This order governs the acquisition and use of "Confidential Information" in this proceeding.

Definitions-

2. "Confidential Information" is information that falls within the scope of ORCP 36(C)(7) ("a trade secret or other confidential research, development, or commercial information").

3. A "qualified person" is an individual who is:

a. An author(s), addressee(s), or originator(s) of the Confidential Information;

b. A Commissioner or Commission staff;

c. Counsel of record for a party;

d. A person employed directly by counsel of record; or

e. A person qualified pursuant to paragraph 10. This includes parties and their employees.

Designation of Confidential Information-

4. A party providing Confidential Information shall inform other parties that the material has been designated confidential by placing the following legend on the information:

CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER

To the extent practicable, the party shall designate as confidential only those portions of the document that fall within ORCP 36(C)(7).

5. A party may designate as confidential any information previously provided by giving written notice to the other parties. Parties in possession of newly designated Confidential

Information shall, when feasible, ensure that all copies of the information bear the above legend to the extent requested by the party desiring confidentiality.

Information Given to the Commission-

6. Confidential Information that is: (a) filed with the Commission or its staff; (b) made an exhibit; (c) incorporated into a transcript; or (d) incorporated into a pleading, brief, or other document, shall be printed on yellow paper, separately bound and placed in a sealed envelope or other appropriate container. An original and five copies each separately sealed shall be provided to the Commission. **Only the portions of a document that fall within ORCP 36(C)(7) shall be placed in the envelope/container**. The envelope/container shall bear the legend:

> THIS ENVELOPE IS SEALED PURSUANT TO ORDER NO. ________ AND CONTAINS CONFIDENTIAL INFORMATION. THE INFORMATION MAY BE SHOWN ONLY TO QUALIFIED PERSONS AS DEFINED IN THE ORDER.

7. The Commission's Administrative Hearings Division shall store the Confidential Information in a locked cabinet dedicated to the storage of Confidential Information.

Disclosure of Confidential Information-

8. Parties desiring receipt of Confidential Information shall sign the Consent to be Bound Form attached as Appendix B. This requirement does not apply to the Commission staff. Confidential Information shall not be disclosed to any person other than a "qualified person," as defined in paragraph 3. When feasible, Confidential Information shall be delivered to counsel. In the alternative, Confidential Information may be made available for inspection and review by qualified persons in a place and time agreeable to the parties or as directed by the Administrative Law Judge.

9. Qualified persons may disclose confidential information to any other qualified person, unless the party desiring confidentiality protests as provided in Section 11.

10. To become a qualified person under paragraph 3(e), a person must:

a. Read a copy of this Protective Order;

b. Execute a statement acknowledging that the order has been read and agreeing to be bound by the terms of the order;

c. Date the statement;

d. Provide a name, address, employer, and job title; and

e. If the person is a consultant or advisor for a party, provide a description of the nature of the person's consulting or advising practice, including the identity of his/her current, past, and expected clients.

Counsel shall deliver a copy of the signed statement including the information in (d) and (e) above to the party desiring confidentiality and to all parties of record. Such notification may be made via e-mail or facsimile. A person qualified under paragraph 3(e) shall not have access to Confidential Information sooner than five (5) business days after receipt of a copy of the signed statement including the information in (d) and (e) above by the party desiring confidentiality.

11. All qualified persons shall have access to Confidential Information, unless the party desiring confidentiality protests as provided in this paragraph. The party desiring to restrict the qualified person(s) from accessing specific Confidential Information must provide written notice to the qualified person(s) and counsel for the party associated with the qualified person(s) as soon as the party becomes aware of reasons to restrict access. The parties must promptly confer and attempt to resolve any dispute over access to Confidential Information on an informal basis before filing a motion with the Administrative Law Judge. If the dispute cannot be resolved informally, either party may file a motion with the Administrative Law Judge for resolution. Either party may also file a motion if the other party does not respond within five days to a request to resolve the dispute. A motion must describe in detail the intermediate measures, including selected redaction, explored by the parties and explain why such measures do not resolve the dispute. After receipt of the written notice as required in this paragraph, the specific Confidential Information shall not be disclosed to the qualified person(s) until the issue is resolved.

Preservation of Confidentiality-

12. All persons who are given access to any Confidential Information by reason of this order shall not use or disclose the Confidential Information for any purpose other than the purposes of preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the Confidential Information secure. Disclosure of Confidential Information for purposes of business competition is strictly prohibited.

Qualified persons may copy, microfilm, microfiche, or otherwise reproduce Confidential Information to the extent necessary for the preparation and conduct of this proceeding. Qualified persons may disclose Confidential Information only to other qualified persons associated with the same party.

Duration of Protection-

13. The Commission shall preserve the confidentiality of Confidential Information for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality. The Commission shall notify the party desiring confidentiality at least two weeks prior to the release of confidential information.

Destruction After Proceeding-

14. Counsel of record may retain memoranda, pleadings, testimony, discovery, or other documents containing Confidential Information to the extent reasonably necessary to maintain a file of this proceeding or to comply with requirements imposed by another governmental agency or court order. The information retained may not be disclosed to any person. Any other person retaining Confidential Information or documents containing such Confidential Information must destroy or return it to the party desiring confidentiality within 90 days after final resolution of this proceeding unless the party desiring confidentiality consents, in writing, to retention of the Confidential Information or documents containing such Confidential Information. This paragraph does not apply to the Commission or its Staff.

Appeal to the Presiding Officer-

15. If a party disagrees with the designation of information as confidential, the party shall contact the designating party and attempt to resolve the dispute on an informal basis. If the parties are unable to resolve the dispute, the party desiring to use the information may move for exclusion of the information from the protection conferred by this order. The motion shall:

a. Specifically identify the contested information, and

b. Assert that the information does not fall within ORCP 36(C)(7) and state the reasons therefore.

The party resisting disclosure has the burden of showing that the challenged information falls within ORCP 36(C)(7). If the party resisting disclosure does not respond to the motion within ten (10) calendar days, the challenged information shall be removed from the protection of this order.

The information shall not be disclosed pending a ruling by the Administrative Law Judge on the motion.

Additional Protection-

16. The party desiring additional protection may move for any of the remedies set forth in ORCP 36(C). The motion shall state:

a. The parties and persons involved;

b. The exact nature of the information involved;

c. The exact nature of the relief requested;

d. The specific reasons the requested relief is necessary; and

e. A detailed description of the intermediate measures, including selected redaction, explored by the parties and why such measures do not resolve the dispute.

The information need not be released and, if released, shall not be disclosed pending the Commission's ruling on the motion.

ORDER NO.

SIGNATORY PAGE

DOCKET NO. ______________

I. Consent to be Bound-

This Protective Order governs the use of "Confidential Information" in this proceeding.

_________________________PGE agrees to be bound by its terms of this Protective Order.

By: ______________________________ ______________________________

Signature & Printed Date

____

II. Persons Qualified pursuant to Paragraphs 3(a) through 3 (d)

______________________________PGE identifies the following person(s) automatically qualified under paragraph 3(a) through (d).

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

III. Persons Qualified pursuant to Paragraph 3(e) and Paragraph 10.

I have read the Protective Order, agree to be bound by the terms of the order, and will provide the information identified in paragraph 10.

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE ___

PRETRIAL BRIEF

OF

PORTLAND GENERAL ELECTRIC COMPANY

February 27, 2008

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by PORTLAND GENERAL ELECTRIC COMPANY	))))	**PRETRIAL BRIEF OF PORTLAND GENERAL ELECTRIC COMPANY**

I. INTRODUCTION

In this docket Portland General Electric Company ("PGE") requests to revise its tariff schedules pursuant to ORS 757.205 and ORS 757.220. This brief is submitted to meet the requirements of OAR 860-013-075.

This case is somewhat different than PGE's immediately prior rate cases. In the prior two rate cases, large new generating facilities were primary factors in the need for the rate case. UE 180/181/184 included Port Westward, and UE 188 was limited to only the costs and benefits of Biglow Canyon 1. PGE successfully brought both of those plants into service, and customers are receiving the benefits through the power costs included in this and previous dockets. While there is not a new generating plant included in this docket,[1] there are significant capital investments in this case, related to hydro relicensing requirements as well as ongoing improvements to our transmission and distribution systems. But that is only one of the cost drivers. This case is about increasing costs PGE is experiencing across a wide range of areas and activities. The policy testimony of Jim Piro addresses the business and regulatory context that is increasing costs. Taken together these cost increases require revised rates and schedules that meet our customers' needs for reasonable services and PGE's need for the opportunity to earn a return on invested capital that is commensurate with similar companies, allowing it to maintain its credit and attract capital.

PGE will have very significant capital needs in the next few years. Hydro relicensing obligations will require significant investment. Phases 2 and 3 of the Biglow Canyon wind

1 The second phase of Biglow Canyon is scheduled to be completed in 2009. PGE anticipates reflecting the costs and benefits of that plant in rates through the recently approved automatic adjustment clause, therefore those costs and benefits are not included in this rate case filing.

generation facility will be completed by the end of 2010. In total, Biglow Canyon will be the largest investment in a generating plant in PGE's history. If approved, AMI will be implemented at a cost of about $132 million. Additional significant environmental controls for the Boardman plant will be necessary. As a result, PGE will be raising capital by issuing debt and equity at levels greater than at any time in the past. Sufficient cost coverage through rates will aid PGE in obtaining this capital at more favorable terms, lowering long-term costs for customers.

II. SUMMARY OF THIS CASE

This case is based on a normalized future test period of calendar year 2009. PGE will seek a schedule in this docket that will allow revised tariff schedules to be implemented on January 1, 2009.

PGE is requesting an increase in base rates over revenues that would be expected based on 2008 prices of $145.9 million, which represents an 8.9% overall increase in PGE's cost of service prices. There are three major categories of cost increases each accounting for about one-third of the requested increase. About one-third of the increase is for fuel and purchased power costs – the costs that would be included in PGE's Annual Update Tariff (Schedule 125) absent this rate case. Increased Operations and Maintenance (O&M) and Administrative and General (A&G) expenses cause a little over one-third of the requested increase. The remaining approximate one-third of the increase is primarily related to increased investment in utility plant, mostly hydro related, and increased capital costs.

PGE requests an authorized return on equity ("ROE") of 10.75%. The projected test year results show that, without a rate increase, PGE will earn a return on equity of approximately 3.4%. That is significantly below PGE's currently authorized ROE, and below the level needed to maintain PGE's credit and attract capital.

The submitted testimony, described below, addresses costs in each area of the company, and supports PGE's request.

Net Variable Power Costs. Each year under Schedule 125, PGE's rates are adjusted to reflect projected net variable power costs ("NVPC") for the coming year, and transition charges or credits for those customers opting for an alternate electric supplier are calculated. Schedule 125 requires PGE to file estimates of the adjustments on or before April 1. That requirement is superseded with this docket. PGE requests a schedule that will allow for a Commission decision of NVPC issues by mid-October consistent with the requirements of PGE's Tariff Schedules 125 and 128, and the November 2008 open access window.

Income Taxes. This filing is a general rate proceeding or other general rate revision under OAR 860-022-0041. The order in this docket will reset the ratios used in the calculation of "taxes authorized to be collected in rates" as used in that rule.

Compliance with OAR 860-013-0075. Attached as Exhibit 1 is the information required by OAR 860-013-0075.

III. TESTIMONY

PGE's testimony and exhibits demonstrate that the Commission should approve this Application. The rates and tariffs proposed will result in rates that are just and reasonable. PGE is introducing twelve pieces of testimony sponsored by the following witnesses:

EXHIBIT NO.	TITLE	WITNESSES
100	Policy	Jim Piro
200	Revenue Requirements	Alex Tooman and Jay Tinker

300	Net Variable Power Costs	Mike Niman and Jay Tinker
400	Production O&M	Steve Quennoz and Jim Lobdell
500	Corporate Support	Jim Piro and Alex Tooman
600	Transmission and Distribution	Steve Hawke
700	Customer Services	Steve Hawke
800	Compensation	Arleen Barnett and Joyce Bell
900	Cost of Capital	Patrick Hager and Kristin Stathis
1000	Return on Equity	Thomas M. Zepp
1100	Load Forecast	Ham Nguyen
1200	Pricing	Doug Kuns and Marc Cody

IV. SUMMARY OF TESTIMONY

Exhibit 100. Jim Piro presents the opening testimony. He describes PGE's business and regulatory environment, the changes PGE is experiencing, the significant factors contributing to the need for a rate increase, and actions by PGE to mitigate the rate request. He also provides support for PGE's proposed decoupling mechanism (Schedule 123) included in this filing. Mr. Piro also introduces the other witnesses providing testimony in this docket.

Exhibit 200. Alex Tooman and Jay Tinker summarize the overall revenue requirement of \$1,732.7 million. Messrs. Tooman and Tinker explain that PGE is using a 2009 test year, and compare the request with the Commission approved revenue requirement and 2007 actual results.

Messrs. Tooman and Tinker explain the taxes and fees assessed on PGE. Their testimony also presents PGE's forecasted capital expenditures. Messrs. Tooman and Tinker also testify to PGE's rate base. The average 2009 rate base is \$2,365.7 million, a significant increase over

2007 test year rate base. Finally, these witnesses also present PGE's unbundled revenue requirement.

Exhibit 300. Mike Niman and Jay Tinker present PGE's NVPC. The initial NVPC forecast for 2009 is $806.7 million. This is an increase of 8% from the 2008 NVPC determined in PGE's recent Annual Updated Tariff proceeding, Docket UE 192. The primary causes of the increase are increased fuel and purchased power costs. As stated above, PGE requests that a schedule is implemented in this docket to allow for a Commission decision of NVPC issues by mid-October consistent with the requirements of PGE's Tariff Schedules 125 and 128, and the November 2008 open access window.

Exhibit 400. PGE's long-term power supply resources and associated costs are presented by Steve Quennoz and Jim Lobdell. Forecasted 2009 costs for power operations and plant-related O&M expenses are about $108 million. These witnesses discuss the primary drivers of increased costs since 2007 including the addition of the Port Westward and Biglow Canyon 1 plants, required maintenance work, licensing requirements, and increased labor and materials costs. These witnesses also address the capital expenditures required as part of the hydro relicensing process at Pelton and Round Butte, the Sullivan plant, and the Clackamas River Hydroelectric Project. The Round Butte Selective Water Withdrawal Tower is expected to be completed and closed to plant in 2009.

Exhibit 500. Jim Piro and Alex Tooman address PGE's administrative and general and information technology ("IT") expenses. Test year A&G expenses are approximately $120 million. The testimony addresses the main reasons for the increased costs including higher labor costs, insurance premiums, research and development costs, higher OPUC fees, higher Western

Electricity Coordinating Council membership costs, new business continuity and emergency management costs, higher IT costs, and payments in lieu of property taxes related to Biglow Canyon. These witnesses also list additional A&G costs that will be included in PGE's errata filing, predominantly related to compliance with FERC requirements.

Exhibit 600. Steve Hawke testifies regarding PGE's transmission and distribution ("T&D") system. He explains the operational and capital costs necessary to do so and the changes in those costs since 2007. T&D operations and maintenance expenses are projected to be approximately $80 million in the 2009 test year. T&D capital expenditures are projected to be over $150 million in 2009.

Exhibit 700. Mr. Hawke also addresses PGE's Customer Services functions and costs. The areas covered by the customer services testimony are responsible for most interactions with retail customers. Customer services costs in the 2009 test year are about $74 million. The testimony explains the major drivers of the cost increases and the steps PGE has taken to minimize costs while providing the service our customers expect and demand.

Exhibit 800. Arleen Barnett and Joyce Bell testify on compensation and human resource issues. The focus of their testimony is total compensation and PGE's practice of setting each total compensation component to the market median. Total compensation in the 2009 test year is approximately $289 million, an increase of 4.8% per year since 2007. The witnesses describe significant changes in this area since 2007.

The witnesses also discuss the particular challenges PGE faces in this area. These include difficulty recruiting skilled employees for certain positions, rising health care costs, and PGE's aging workforce.

Exhibit 900. Patrick Hager and Kristin Stathis present PGE's testimony on cost of capital. The witnesses discuss PGE's capital structure and cost of long term debt. PGE's long-term debt for 2009 has an effective interest rate of 6.57%. This includes three new debt issuances planned for 2008 and 2009.

This testimony also discusses PGE's plan to issue $200 million in equity in 2009. PGE will incur issuance costs projected to be about $7 million. As discussed in the revenue requirement testimony, Exhibit 200, to mitigate rate impacts PGE proposes to amortize these equity issuance costs over 10 years.

After the new debt issuances in 2008 and 2009, and the planned equity issuance in 2009, PGE expects that at year end 2009 the equity portion of its capital structure will be approximately 50%. That is the same level the Commission used to set rates the last time it addressed PGE's capital structure.

These witnesses also address several risks and uncertainties that PGE faces, that are relevant to PGE's cost of capital and also to the appropriate return on equity to be used in this docket.

Exhibit 1000. Thomas M. Zepp addresses PGE's equity costs. Mr. Zepp addresses the risks PGE faces compared to the cost of common equity that faces a typical electric utility. Mr. Zepp concludes that PGE specific risks increase PGE's cost of equity by no less than 20 basis points above the cost for a typical utility. Relying on the Discounted Cash Flow and Risk Premium models, and recently earned and authorized ROEs, the witness concludes that PGE's required return on equity falls in a range of 10.7% to 11.5%, and that PGE's requested ROE of 10.75% is conservative and should be adopted.

Exhibit 1100. Ham Nguyen presents PGE's load forecast for 2009. He forecasts that total retail loads will increase 3.65% from the 2007 level. PGE will update the load forecast during this case as more information becomes available.

Exhibit 1200. Doug Kuns and Marc Cody testify on pricing. They detail the tariff building blocks used to develop rates, the revenue requirement process, and marginal costs.

PGE has designed the rates based on cost causation. The proposed rate change, including power cost related changes, is 8.9% overall before changes to supplemental schedules, and 7.1% after changes to supplemental schedules.

This testimony also discusses several tariff changes proposed in this case. A proposed decoupling mechanism is explained. Within the Annual Update Tariff, Schedule 125, PGE proposes to allocate NVPC in a manner similar to costs under the recently adopted Schedule 122 Renewable Resources Automatic Adjustment Clause. PGE also proposes a change to Schedule 125 in order to more accurately reflect cost changes due to movement of customers between cost of service schedules and multi-year cost of service opt-out schedules. These witnesses also describe a proposal to more narrowly define the calculation of the Large Nonresidential Load Shift True-Up in Schedule 128.

The testimony also describes other proposed tariff changes, and also minor modifications to some Schedule 300 charges.

V. REQUEST FOR APPROVALS

PGE requests that the Commission issue an order:

(1) Approving the requested rate changes;

(2) Approving the proposed tariffs; and

(3) Ordering PGE to record its equity issuance costs as a regulatory asset and amortize the asset over 10 years on its books and for ratemaking purposes.

Dated: this 27th day of February, 2008.

Respectfully submitted,

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Exhibit 1
Case Summary
($000)

Total Revenue Requirement	1,732,713
Change in Revenues Requested	
Total Change in Revenues Requested	145,892
Total Change net of RPA[1]	145,892
Percent Change in Base Revenues Requested	8.9%
Percent Change net of RPA	8.9%
Test Period	2009
Requested Rate of Return on Capital (Rate Base)	8.66%
Requested Rate of Return on Common Equity	10.75%
Proposed Rate Base	2,365,737
Results of Operation	
A. Before Price Change	
Utility Operating Income	117,800
Average Rate Base	2,362,677
Rate of Return on Capital	4.99%
Rate of Return on Common Equity	3.41%
B. After Price Change	
Utility Operating Income	204,837
Average Rate Base	2,365,737
Rate of Return on Capital	8.66%
Rate of Return on Common Equity	10.75%
Net Effect of Proposed Price Change	
A. Residential Customers	9.5%
B. Small Non-residential Customers	7.9%
C. Large Non-residential Customers	8.5%
D. Lighting & Signal Customers	2.6%
Note: Percent Changes are on a cycle basis for Cost of Service Customers	

[1] Due to the suspension of RPA benefits by the Bonneville Power Administration, PGE is currently not passing on RPA benefits.

UE ___ / PGE / 100
PIRO

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

James J. Piro

February 27, 2008

Table of Contents

I. Introduction

Q. What is your name and position with PGE?

A. My name is James J. Piro. I am the Executive Vice President and Chief Financial Officer for PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. I summarize our filing and other testimonies.

Q. Please summarize your request.

A. Our costs are steadily increasing as compliance with new regulatory requirements demands more labor and other resources and inflation continues to impact all elements of our business including fuel and purchased power. In 2008, we are able to absorb these increases, which allowed us to increase rates only for our new wind farm, Biglow Canyon, and for net variable power costs. For 2009, however, margins from load growth will not be sufficient to cover the cost of our business. We do not undertake this filing lightly. We recognize that our customers, and especially our low-income customers, are experiencing significant increases in their energy bills. This filing does not help that situation. However, if we are to meet our mandate of providing safe, reliable power to our customers, an increase in our prices is necessary.

We are requesting an increase in revenue requirements of about $146 million, which translates to an increase in our cost of service prices of approximately 8.9%. It is comprised of three major categories of cost increases. First, roughly one-third of the increase is the result of fuel and purchased power cost increases. The fuel and power markets are continuing to feel the effects of supply constraints, and PGE is directly impacted by these market forces. Had we not filed this general rate case, we would have requested essentially this amount through our Schedule 125 Annual Power Cost Update Tariff (AUT).

Second, a little over one-third of the increase is due to increases in Operations and Maintenance (O&M) and Administrative and General (A&G) expenses. These costs are driven by increases in the cost of labor, materials, supplies, and new compliance related costs.

The final third of the increase is related to several items including: a larger rate base (e.g., the Selective Water Withdrawal Tower at our Pelton Round Butte Hydro Project and fuel inventories), higher other non-O&M expenses (e.g., depreciation and non-income taxes, such as payroll taxes and franchise fees) and a higher cost of capital.

Q. Since PGE has experienced higher income levels in 2007, why do you need this increase for 2009?

A. The difference in expectations compared with 2007 is the result of several factors. First, as described above (and in more detail in the testimony that follows), PGE's costs are rising. Our costs for 2008 will be higher than 2007 and we expect they will continue to rise in 2009. Second, the favorable results for 2007 occurred because of significant items that relate to prior periods (e.g., $20.4 million for the Boardman deferral, and $5.6 million for California receivables) and favorable results related to 2007 power costs (e.g., reasonable hydro conditions and favorable plant operations) that will result in a refund to customers from PGE's power cost adjustment mechanism. In addition, PGE's positive results for 2007 are compounded by the effects of SB 408, which result in PGE accruing additional revenue to reflect the eventual collections from customers for the higher taxes associated with higher income levels.

Q. Is this rate case similar to PGE's recent rate cases in dockets UE 180 and UE 188?

A. No. Port Westward and Biglow Canyon were the primary factors that created the need for those rate cases. This case is not about a new large generating facility. Rather, it is about a wave of regulation and market forces with multiple and varied impacts over a wide range of activities. None of these impacts by themselves warrants a general rate case, but taken together the cumulative impact requires this filing.

Q. How have you organized your testimony?

A. Following this introduction, I organize my testimony as follows:

- Section II: PGE's Operating Environment;
- Section III: New Challenges;
- Section IV: Other Significant Contributing Factors – Power Costs, Labor and Materials, and Health Care;
- Section V: Mitigating Actions;
- Section VI: Policy;
- Section VII: Overview of PGE's Testimony; and
- Section VIII: Qualifications.

II. PGE's Operating Environment

Q. Please discuss the environment under which PGE currently operates.

A. The environment is an interesting and challenging one, especially in the electric utility business. We must comply with new regulatory requirements on all fronts. From state regulation, beginning with SB 1149 through SB 408 and the recent renewable resource portfolio legislation, to new federal regulation in the form of new Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Commission (NERC) reporting requirements, to new hydro relicensing requirements, to continued corporate regulation from Sarbanes-Oxley, we must comply with more rigorous rules and regulations than ever before. Moreover, in a carbon-constrained world, new environmental standards require us to balance new interests and concerns. We must balance our traditional role as an energy utility with an emerging framework that recognizes the impact of energy production and consumption on the environment and global resources. Both compliance with new regulations and responding to the new challenges require additional resources and increase our costs.

Q. Are these new requirements specific to PGE?

A. No. The increase in regulatory compliance is industry-wide. To name just one example, FERC Order Nos. 890 and 890-A, which amend FERC Order Nos. 888 and 889 to ensure that transmission services are provided on a basis that is just, reasonable, and not unduly discriminatory or preferential, impose new and substantial reporting obligations. These are on top of the additional regulatory requirements imposed by NERC and Western Electricity Coordinating Council (WECC) Reliability Standards which FERC made mandatory in

Order No. 693 and subsequent orders.[1] These new regulatory frameworks are an important foundation for our transmission network and a reliable infrastructure, but they demand more resources and increase costs. For example, PGE now has to fully document our compliance with each requirement under each standard. We are also subject to a range of WECC enforcement actions, including quarterly Self-Certifications on our 13 functional responsibilities[2] providing evidence of compliance for WECC Spot Checks, and participating in week-long WECC audits on a three-year cycle.

Q. Are there any company-specific areas relating to increased regulation?

A. Yes. After recently completing the relicensing of two major hydroelectric projects (Pelton Round Butte and Willamette Falls), PGE is in the process of obtaining a new long-term license for the Clackamas River Hydroelectric Project. We use a highly collaborative, process-oriented approach in which we seek to forge a coalition with multiple interest groups. Technical groups representing diverse interest groups tackle individual issues as the FERC process must analyze fish and wildlife, recreational, land use, cultural, and aesthetic issues, along with energy production. These efforts successfully brought our customers substantial benefits by ensuring that these hydro generating assets remain part of PGE's resource mix for the long-term future.

Q. Does hydro relicensing impose additional regulatory mandates?

A. Yes. Successful relicensing efforts bring with them new regulatory requirements. This case includes an increase in hydro Operations and Maintenance (O&M) costs to meet additional and/or new licensing requirements at our relicensed hydro facilities. The relicensing effort

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1 As of February 2008, there are 83 NERC Reliability Standards and 8 WECC Reliability Standards that are mandatory on users, owners and operators of the Bulk-Power System, including PGE, and another 11 NERC Reliability Standards that have been approved by FERC and will become mandatory at a future date.

2 PGE is registered as the following: Balancing Authority, Transmission Operator, Transmission Owner, Load-Serving Entity, Distribution Provider, Planning Authority, Transmission Planner, Resource Planner, Generation Operator, Generation Owner, Purchasing-Selling Entity, and Transmission Service Provider.

also requires substantial capital investments. For example, PGE expects to complete the Round Butte Selective Water Withdrawal in 2009 at a cost to PGE of $81 million.

Q. Have you quantified the impact of heightened regulatory requirements?

A. Yes. Most of the impacts are cumulative (and in some cases compounded) in nature and occur throughout the organization, so that it is not possible to entirely quantify the exact impact of each new regulatory requirement. I do, however, estimate that the readily identifiable increases associated with compliance total about $11.5 million from 2007 to our 2009 forecast, and include the following examples:

- $4.8 million for hydro relicensing requirements;
- $750,000 for 7.5 full time equivalent (FTE) employees to comply with FERC Order 890-A;
- $2.0 million for OPUC Fees in A&G based on a change in statute;
- $1.0 million for the inspection of the Kelso-Beaver pipeline as required by FERC;
- $700,000 for costs related to PGE's membership in the WECC;
- $400,000 to establish a Business Continuity and Emergency Management department (while not required by a specific government mandate, this effort is a necessary response to heightened expectations placed on essential service providers); and
- $650,000 for additional FERC compliance activities.

III. New Challenges

Q. What are PGE's new challenges?

A. PGE must face the challenges of a carbon-constrained world, as it transitions to be a more sustainable energy provider. This requires PGE to balance its traditional role of providing safe and reliable electricity service at fair and reasonable prices with the environmental and global impacts of meeting the energy needs of our customers. Initiatives like Oregon's renewable energy standard (RES), global climate change, and the rapid pace of technology advances present time-sensitive issues that cannot be avoided or delayed. This rate case includes research and development costs for highly efficient community-scale infrastructure, solar-ready infrastructure, carbon capture, and tree planting for environmental benefits, to name just a few of the new activities necessary to respond to our customer and regulator environmental demands.

Q. How are you investing to meet these new challenges?

A. We plan new, sustainable and varied resources to meet load growth and the RES requirements. Our IRP currently before the Commission identifies our plans to add new energy and capacity resources to meet our customers' needs for electricity. By 2010, we expect to complete construction of Biglow Canyon Phases 2 and 3. Through our hydro relicensing efforts and Best Available Retrofit Technology (BART) to mitigate the environmental impact of our operation of the Boardman plant, PGE continues to make capital investments to address emerging environmental requirements. PGE's AMI proposal and associated programs for demand response, outage management, and distribution asset utilization will provide customers with substantial long-term savings. While the above plant investments are not included in this rate case proposal, they are illustrative of the changes that are occurring.

Q. Are you also facing challenges in your workforce?

A. Yes. By 2009, one-third of PGE's entire workforce will be eligible for retirement. Currently, over half of PGE's non-bargaining and 41% of bargaining power generation employees are eligible for retirement. This puts a premium on succession planning, training, and filling vacant positions in a tight skilled-labor market, which pushes labor costs higher.

Q. Is strong fiscal management a high priority?

A. Yes. In the near term, we plan to make substantial investments in cost-effective new renewable resources and environmental mitigation projects, which will require access to the equity and debt markets. In 2009, PGE anticipates issuing $200 million of equity, with the attendant equity issuance costs. We also plan to issue $250 million of debt in 2009. Keeping a strong balance sheet and maintaining investment grade credit ratings are essential to our access to debt and equity markets at reasonable and competitive rates. Ultimately, customers will reap the benefit from cost-effective financing rates for these important capital projects.

Q. Are there other parts of this case that evidence these new challenges?

A. Yes. In addition to the cost of accessing capital markets, federal securities regulation in the form of Sarbanes-Oxley continues to require substantial company resources to ensure compliance with these important investor protections.

IV. Other Significant Factors – Power Costs, Labor and Materials, and Health Care

Q. In addition to increased regulatory demands and new challenges, are there other factors that increase costs?

A. Yes. PGE sees a continuation of the recent trends, especially in plant construction, that have increased the key components of our costs. For example, as we've experienced over the last 10 years, power prices continue to rise, accounting for approximately one-third of the revenue requirement increase in this case (of the total revenue requirement increase of $146 million, power costs account for $53 million[3]). The primary reasons for the power cost increase are rising fuel costs and the escalating cost of purchased power, over which we have little, if any, control.

Q. Are the increases in the cost of labor and O&M continuing to outpace inflation?

A. Yes. The cost of goods and materials continues to increase in response to the global energy market as construction, production and consumption in China, India and other industrial countries increase the demand for these resources, pushing prices higher (see PGE Exhibit 101). In addition, like other utilities, PGE must also locate, recruit and hire a skilled workforce in a very tight labor market. Competition for these skilled laborers is so great that the search for utility linemen is no longer limited to local and regional labor markets. We see other utilities recruiting nationally for these skilled laborers, even offering signing bonuses and other incentives to attract new recruits. The prospect of significant retirements within PGE's mature and experienced workforce further underscores the need to fill vacancies and the increasing cost of doing so.

Q. Are benefits and health care costs also increasing?

3 While these power costs are part of our general rate case filing, the power cost component of the increase would have been included in customers' rates through Schedule 125, annual power cost update (as approved in UE 180), whether or not we filed this general rate case.

A. Yes. Health care costs have been increasing faster than inflation for some time. This trend is likely to continue for the foreseeable future. Some of PGE's multiple challenges in 2009 are escalating health care costs and managing health care issues, while building competitive benefit packages to recruit and retain a skilled workforce.

V. Mitigating Actions

Q. Has PGE undertaken any efforts to control costs?

A. Yes. PGE engages in continuous efforts to control and minimize costs, as well as improve system reliability and enhance customer service and access, while making our business more efficient.

Q. Mr. Piro, can you give specific examples of how PGE controls its costs?

A. Yes. PGE has an annual budgeting process, which establishes both capital and expense levels for upcoming years. These budgets are based on our on-going requirements to deliver safe, reliable power and provide efficient customer service to our customers. The process considers known and measurable changes for new programs, processes, or services and is reviewed by PGE executives to ensure that only prudent increases are incorporated in the budget. Each year, we review the variance of actual results to budgeted amounts to ensure that PGE's costs are within expectations and significant deviations are justified. PGE also has a Capital Review Group (CRG) that reviews all capital jobs to determine which ones should be implemented based on their costs, benefits and regulatory requirements relative to available capital funds. This process is designed to obtain the maximum value from our capital projects for customers within the context of our business requirements. Some examples of cost reductions we have pursued in recent years include:

- In 2007, PGE discontinued the vendor's maintenance agreement for our customer information system (CIS), Banner, after determining that it was more cost effective to bring the system expertise in-house. As a result of this change, PGE reduced annual maintenance costs by approximately $650,000 by eliminating the annual maintenance agreement of approximately $1.1 million and replacing it with PGE labor of approximately $450,000. In addition to the financial benefit, PGE is able to develop a skilled internal workforce to address critical maintenance and system modification activities without having to rely on outside resources.

- In 2007, PGE completed the migration of its e-mail system from GroupWise to Outlook. This conversion will save approximately $170,000 annually in software licensing and maintenance costs.
- In 2007, PGE implemented an Integrated Absence Management Program that will centralize absence tracking and help reduce employees' return-to-work time. These programmatic changes include the replacement of sick leave with short-term disability for our exempt employees which should reduce future years' benefit costs.
- In 2007, PGE implemented an Accounts Receivable Conversion (ARC) process that converts paper checks to electronic payments and sends the bank an electronic file rather than paper checks. As a result of this project, PGE expects to realize an estimated annual savings of $160,000 from the following areas:
  - A decline in bank fees for paper items converted to ARC and for current electronic file items;
  - The elimination of courier fees for Wells Fargo and Bank of America; and,
  - A decrease in the amount of encoding supplies used.
- In 2005, PGE, Qwest and Comcast entered into a Coordinated Work Crew Project to address the complex, time consuming, and costly method of completing National Electric Safety Code (NESC) Violation Corrections on joint-use utility

poles. These Coordinated Work Crew Projects implement a process for simultaneously addressing pole attachment violations for communication and power lines. Efficiencies from this joint venture will include a reduction in the number of trips to a utility pole, a more effective work process, and a well-built and NESC-compliant communication and power infrastructure. To date, two projects have been completed, one in the Oregon City area and a second in the Lake Oswego area. In 2008, this joint venture concept will be expanded to perform pole replacements necessary within the PGE, Qwest and Comcast service territories.

- Between 2008 and 2010, PGE plans (with Commission approval) to implement an advanced metering infrastructure 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-way system, sends commands to the meter. AMI provides two types of benefits:
  - Operational costs savings as direct benefits of the system, which PGE estimates to be approximately $18.2 million in the first full calendar year after full deployment is completed (now expected to be 2011).
  - Customer and system benefits that are derived by programs that the AMI system supports or provides a platform for developing (e.g., demand response, distribution asset utilization, and outage management). These benefits have

the potential to produce significant cost savings in the future but also require additional costs and investment to implement.

- PGE's FITNES program has increased the life of a typical wood pole from approximately 35 years to 55 years and reduced annual pole losses from 12% to 0.7%, saving millions of dollars in replacement costs.

Q. What is PGE doing to mitigate increases in health care costs?

A. PGE performs internal studies to understand which health issues are adding the most costs, and we continue to invest in internal health and wellness programs (e.g., our Energy for Life program) to help lower health risk factors that should reduce long-term medical issues and reduce plan costs. We provide tools for persons identified as high risk during health screenings to lower their medical risks. PGE also aggressively negotiates with vendors for favorable terms for provider contracts, and when health plan costs do rise, employees share the increased burden, aligning their interests with PGE’s interests in keeping costs down.

In addition, PGE participates in public forums regarding health care reform in Oregon. For example, PGE President and CEO, Peggy Fowler, is leading the Oregon Business Plan's health initiative, as well as participating as a Board Member for Regence Group and Regence Blue Cross/Blue Shield. The Oregon Business Plan recommends: 1) value-based purchasing strategies, 2) health information technology and infrastructure, and 3) planning to improve access to health care. As is appropriate and possible for PGE, our benefits negotiations also include components of these recommendations.

Q. Have you proposed any accounting changes to reduce this request?

A. Yes. As discussed in PGE Exhibit 900, PGE anticipates issuing $200 million of equity in mid-2009, with equity issuance fees estimated at 3.5%. Instead of including this entire amount in the test year, PGE proposes to recover the equity issuance costs over a 10-year period. This will reduce the revenue requirement by approximately $10 million in this case.

VI. Policy

Q. Do you propose changes to the power cost recovery framework adopted in UE 180?

A. No. In UE 180, the Commission authorized annual power cost updates through Schedule 125 (the AUT) and a power cost adjustment mechanism (PCAM) for the recovery or refunding of substantial variances between actual and forecasted power costs (Schedule 126). After a series of contentious Commission proceedings in which the parties and the Commission analyzed the appropriate balance of risks and rewards associated with power costs, the Commission adopted these mechanisms as a long-term framework. PGE's 2008 rates reflect the first AUT and the first PCAM will likely yield a refund to customers for 2007. With just one year of experience with these long-term mechanisms, we think it would be premature to change frameworks. Accordingly, we seek no changes to the basic framework of the AUT and PCAM adopted in UE 180. We propose modest modifications to the specific terms of Schedule 125 and to the Monet model that PGE uses to forecast its power costs.

Q. How will you update PGE's power cost forecast for 2009 rates?

A. We propose to update PGE's power costs in this general rate case docket. Under the AUT, annual updates are processed under a proceeding that begins with an initial filing on April 1. For 2009 rates, we will update the annual power cost forecast in this general rate case, not in a separate power cost proceeding.

Q. Does this require a separate schedule for the power cost portion of this general rate case?

A. Yes. Because PGE must post its power cost prices by November 15 to offer customers direct access options, we need a final order on the power cost annual update portion of the general rate case by October 17, 2008.

Q. Do you have dates for updates to the power costs portion of the general rate case?

A. Yes. We propose the following schedule for the power cost updates:

- April 1 – remaining plant updates and any Monet errata corrections to the February 27 filing;
- July – update power, fuel, and transportation/transmission contracts; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads;
- September – update power, fuel, and transportation/transmission contracts; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads; and
- November – final updates of power, fuel, and transportation/transmission contracts and gas and electric forward curves.

Q. Are you proposing a decoupling mechanism in this case?

A. Yes. We are proposing a Sales Normalization Adjustment (SNA).

Q. Please summarize your SNA decoupling proposal.

A. The SNA is a simple balancing account and rate adjustment process that greatly diminishes the disincentives we confront when seeking to support and encourage innovative and effective programs to improve customer energy efficiency. At the same time, the decoupling mechanism allows us to maintain existing pricing structures for customers, which give price signals that support energy efficiency efforts.

The decoupling mechanism we propose is consistent with the general decoupling structures the Commission and several other utility commissions throughout the country have reviewed and implemented. It is a simple and straightforward cost recovery "true-up" adjustment mechanism that removes the financial disincentives we experience when we support efforts to encourage customers to pursue energy efficiency. The disincentives are manifest through reduced energy usage that lowers PGE's revenues, particularly revenues to cover the fixed costs of PGE's operations. Decoupling mechanisms are necessary because the traditional regulatory model and pricing structures cause earnings to fall when customers conserve energy.

Q. To which customer groups does the proposed decoupling mechanism apply?

A. Our proposed decoupling mechanism, implemented through Schedule 123 applies to residential (Sch. 7), small nonresidential customers (Sch. 32 and 532) and large nonresidential customers with loads less than 1 MWa. For the latter customer group, we propose a limited incremental energy efficiency savings-related Lost Revenue Recovery mechanism rather than true decoupling for the applicable portion of the large nonresidential customer class. Very large nonresidential customers are not included in our proposal. The specific elements of Schedule 123 are further described in Exhibit 1200.

Q. Why is a decoupling mechanism important to put into place now?

A. It is clear that the regulatory environment and new challenges described earlier will cause energy efficiency to be an increasingly important part of our energy future. Unfortunately, the existing regulatory structures leave utility shareholders absorbing costs while society and customers gain the long-term benefits of expanding energy efficiency efforts. This situation is inequitable and not conducive to creating innovative and cost-effective programs and resource acquisitions to ramp up energy savings efforts.

The disincentives we note are not hypothetical. For example, if PGE's residential customers reduce loads by just 0.5% per year, we estimate lost margins of approximately $2 million in the first year and growth by an equal amount each year (without a general rate case).

Q. What will change if the Commission adopts PGE's proposed decoupling mechanism?

A. First and foremost, our decoupling proposal is likely to foster more opportunities for us to support expanding energy efficiency efforts. Decoupling is not a "magic bullet," but one leg of a platform of policies and practices that supports public goals to achieve energy efficiency and limit environmental impacts. Without decoupling, the platform is not as robust as it could be.

We have actively supported additional funding for energy efficiency efforts of the Energy Trust of Oregon and, in fact, were a prime mover in achieving legislation that allows additional energy efficiency funding through electric prices. We are committed to working with interested parties either within the context of this rate case or outside it to identify and fund expanded energy efficiency investments and other cost-effective demand-side measures.

Q. What provisions do you propose to ensure that Schedule 123 rate adjustments are related to energy efficiency impacts and similar customer-related changes in usage and not extremes in weather or general economic activity level?

A. As implied by the name "Sales Normalization Adjustment," we propose to apply the adjustment to weather-normalized actual loads to determine the revenues from energy charges. The exact mechanism to accomplish this is described in PGE Exhibit 1200. This assures that the mechanism is not influenced by weather variances (i.e., PGE continues to retain this risk).

Further, as an absolute limit to rate changes resulting from the mechanism, we propose that any annual adjustment in rates caused by a Schedule 123 adjustment will not exceed 2%. We believe this "circuit breaker" provision gives customers an assurance that any rate impact will be relatively small.

Our SNA proposal captures the effects of both decreases in load caused by energy efficiency as well as load growth in normal usage per customer. In other words, this removes not only a major disincentive to support energy efficiency programs but also the similar incentive to increase usage by our residential and small commercial customers. Thus, the mechanism balances both load increases and decreases and the utility is truly held indifferent.

Q. Please describe in more detail the design of the Schedule 123 mechanism.

A. The SNA is exclusively focused on the recovery of a defined subset of our costs recognized as "Fixed Costs." Fixed Costs are those costs that do not typically vary by the amount of energy (kWh) consumed over a year by customers. These fixed costs generally provide the capability of the system to meet customers' demands and include distribution, transmission and fixed generation costs regardless of the actual amount of energy transmitted over the system to meet customer requirements. With respect to generation costs, the variable costs, such as fuel, are not included in our proposal.

Our proposed SNA for fixed cost recovery is a true-up mechanism with the following attributes:

1) it will establish the monthly fixed costs to be recovered on a per customer basis for each applicable customer class based on the last approved general rate case;
2) each month the mechanism will determine the dollar difference (positive or negative) between actual dollar amounts received from customers through their energy charges for fixed costs and the dollar amount that would have been received if the fixed cost rate (dollars per customer per month) had been in effect; and
3) annually determine and apply as an on-going forward basis a Schedule 123 adjustment rate to applicable customers to either refund or collect the difference described above.

For Large Nonresidential customers, a "fixed cost per customer" decoupling mechanism is not feasible since these customers vary significantly in size and are served at different voltage levels. We identified two alternatives that could be used to reduce the disincentives for additional energy efficiency for this customer class. The first alternative is a limited Lost Revenue Recovery (LRR) mechanism for Large Nonresidential customers with usage less than 1 MWa in the previous calendar year. (We exclude customers over 1 MWa since they are not eligible for incremental energy efficiency programs.) While the process to determine the lost revenue amounts (positive or negative) to include in the balancing account is different than the Schedule 7 and 32 decoupling proposal, the purpose of the LRR is similar and focuses on energy efficiency savings. This lost revenue proposal would currently be limited to the effect of energy savings as reported by the Energy Trust of Oregon resulting from our incremental energy efficiency program presently before the Commission. In the future, additional programs could be added as they are approved.

The second alternative is a "load-based" decoupling mechanism. Under it, a baseline load amount would be determined for applicable customer classes by applying the load growth estimates from the current IRP to test year loads of the last general rate case. Any difference between this baseline and actual loads for a given year would be applied to a fixed cost per kWh rate determined in the rate case to determine an adjustment amount.

Both alternatives have positive and negative aspects, and we are willing to consider both as we seek a solution to the disincentive issue. For the purposes of this filing, we have included the LRR in our decoupling tariff as it is the more simple and straightforward alternative.

Through our decoupling proposal, PGE's recovery of fixed costs will no longer be tied to the kWh sales volume of customers, thus removing the financial penalties associated with supporting energy efficiency, (such as PGE's proposed incremental energy efficiency funding), distributed generation and other sustainability actions by customers that reduce kWh usage.

Q. Has decoupling been applied in Oregon?

A. Yes. The OPUC has both accepted and rejected decoupling proposals over the years. Currently, NW Natural operates with a decoupling mechanism. The Commission has thoroughly examined the issues associated with decoupling over the years and as early as 1992, the Commission recognized the need to align regulatory policy with energy efficiency. In UM 409 (Order No. 92-1673, p.13) the Commission stated that:

> We are persuaded that the connection between profits and sales should be severed. As long as the regulatory system provides that increased sales may

> lead to increased profits, a conflict will exist between the motivation to sell energy and the motivation to promote reduction in energy consumption.

We believe that now is an opportune time for the Commission to remove the partially misaligned policies associated with traditional rate setting. Decoupling has received much attention in Oregon and other states. Following extensive review, Idaho Power currently has a three-year decoupling pilot in place in Idaho.

Q. Doesn't decoupling shift risks from PGE to the customer?

A. No. Let's look at what risks customers and PGE bear. Under the current system of fixed cost recovery through energy charges, customers are at risk of paying too much at times just as PGE is at risk of receiving too little at other times. The decoupling mechanism we propose removes this risk for PGE and customers alike. Moreover, PGE continues to absorb risk related to the recovery of its fixed costs under the proposed decoupling mechanism. For example, PGE bears such risks as weather variability, the actual number of customers, and increases in actual costs.

Q. Will decoupling add to the number of rate changes PGE needs to implement during the year?

A. No. PGE proposes to change the decoupling adjustment annually to coincide with the annual change in rates resulting from SB 408. That is, we will file any decoupling changes on April 1 of each year to be effective on June 1. Therefore, this adjustment will not create the need for any change to our rate change implementation schedule. Decoupling may, in fact, assist in limiting the need for general rate cases in the future due to better cost recovery provided through the mechanism.

Q. Will decoupling result only in an increase to customer bills?

A. No. The adjustment can also result in benefits flowing back to customers when volumetric charges recover more revenue due to increases in usage per customer.

VII. Overview of PGE's Testimony

Q What other testimony is presented in this case?

A. PGE is presenting the following direct testimony:

Exhibit 200 summarizes the overall 2009 test year revenue requirement, comparing the request with the approved amounts in UE 180, UE 188, and UE 192. This testimony discusses PGE's rate base, capital expenditures, and PGE's unbundled revenue requirement.

Exhibit 300 presents PGE's net variable power costs (NVPC), including our proposed changes to the Monet model. The forecast for 2009 NVPC is approximately $807 million. This testimony also compares the 2009 NVPC forecast to the current 2008 AUT.

Exhibit 400 supports PGE's Fixed Power Costs for 2009. It identifies new resources, including new power supply resources, power contracts and transmission contracts. It presents PGE's plant and power operations test year O&M and capital addition expenses. This testimony also updates PGE's hydro relicensing efforts, including capital investments required by recently renewed hydro licenses.

Exhibit 500 explains PGE's 2009 test year corporate support costs. Inflation is the primary reason for the increase in costs, especially for benefits that continue to increase at a higher rate than general inflation. This testimony addresses cost increases for new FERC compliance requirements and other regulatory expenses.

Exhibit 600 presents PGE's transmission and distribution costs. This testimony describes PGE's maintenance programs for transmission and distribution facilities, and the O&M test year forecast for these facilities.

Exhibit 700 explains PGE's Customer Service functions and costs. This area is responsible for most communications with customers. The testimony addresses the primary reasons for the cost increase, namely wage inflation, increasing number of customers and customer communications, and implementing programs and services that respond to customers' needs.

Exhibit 800 presents PGE's total compensation costs, which reflect our practice of setting each component of a total compensation package at the market median. This testimony addresses PGE's primary challenges in this area, specifically recruitment and retention in a tight labor market, rising health care costs, and an aging workforce.

Exhibit 900 supports PGE's forecasted cost of capital for 2009. It discusses PGE's cost of long-term debt and risk, and supports PGE's proposed capital structure.

Exhibit 1000 addresses PGE's equity costs, applying the Discounted Cash Flow and Risk Premium models to support a 10.75% return on equity.

Exhibit 1100 explains PGE's load forecast. PGE forecasts that 2009 total deliveries to customers will increase 3.65% from the 2007 weather-adjusted level.

Exhibit 1200 presents PGE's proposed tariffs, including the building blocks used to develop rates, proposed changes to Schedule 125, the revenue requirement process, marginal costs, and the proposed decoupling mechanism.

VIII. Qualifications

Q. Mr. Piro, please describe your educational background and experience.

A. My name is James J. Piro. I received a Bachelor of Science degree from Oregon State University in Civil Engineering in 1974 with an emphasis in Structural Engineering. In addition, I have taken postgraduate courses in engineering, accounting, economics, and rate making. I am a registered Professional Engineer in Civil Engineering in the State of California (Registration No. 28174). I joined Portland General Electric in 1980 and have held various positions in Generation Engineering, Economic Regulation, Financial Analysis and Forecasting, Power Contracts, Economic Analysis, Planning Support, Analysis and Forecasting, and Business Development. I was elected Vice President of Business Development in 1998 and then became Chief Financial Officer and Treasurer on November 1, 2000. I was then named Senior Vice President, Finance, Chief Financial Officer and Treasurer on May 1, 2001, and entered my current position as Executive Vice President, Finance, Chief Financial Officer and Treasurer effective July 25, 2002.

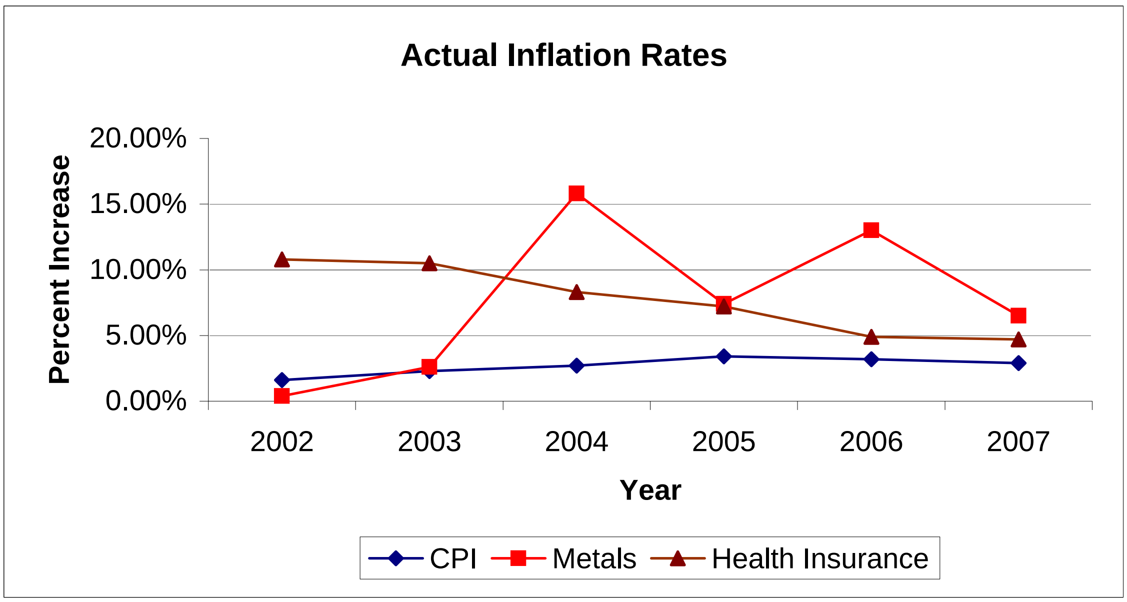
Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit 101
Actual Rates of Inflation

Category	2002	2003	2004	2005	2006	2007
Metals	0.40%	2.60%	15.80%	7.40%	13.00%	6.50%
Health Insurance	10.80%	10.50%	8.30%	7.20%	4.90%	4.70%
Consumer Price Index	1.60%	2.30%	2.70%	3.40%	3.20%	2.90%



Source: U.S. Economic Outlook; Global Insight; January 2004, January 2006, January 2008

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I. Introduction

Q. Please state your names and positions with PGE.

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

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

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present PGE's $1,732.7 million revenue requirement for the 2009 test period. On an average rate base of $2,365.7 million, this revenue requirement will allow PGE an opportunity to earn an 8.66% rate of return and a 10.75% return on average common equity of 50% in 2009. PGE Exhibit 201 summarizes the development of PGE's 2009 revenue requirement.

In addition to presenting this integrated or bundled revenue requirement, we also present and discuss our unbundled revenue requirement in Section VIII.

Q. What increase in rates does PGE request in this proceeding?

A. PGE's revenue requirement is $145.9 million higher in 2009 than the revenues we would expect based on 2008 prices, which reflect approved rates in UE 180, UE 188, and UE 192. Therefore, PGE requests that rates be adjusted on January 1, 2009, to yield $145.9 million of additional revenues (about 8.9% overall) on an annualized basis. PGE Exhibit 1200 describes the prices PGE proposes to allow an opportunity to recover our 2009 revenue requirement.

Q. Please discuss the impact of net variable power costs (NVPC).

A. PGE's initial forecast of NVPC for the 2009 test year is $806.7 million, or $43.5 per MWh of retail calendar year load. PGE's final 2008 NVPC forecast used to set rates in UE 188 / UE 192 was $744.8 million, or $40.7 per MWh of retail calendar year load. Thus, increases in unit NVPC are responsible for $53.0 million of the total $145.9 million base rate increase sought in this proceeding. NVPC are further described in PGE Exhibit 300.

Q. What other cost components are responsible for PGE's $145.9 million request in this proceeding?

A. Table 1 below itemizes the sources of PGE's $145.9 million request in this proceeding.

Table 1
(Sources of PGE Rate Request in $Millions)

Source	Impact
Higher NVPC	$61.9
Revenue Growth (unit NVPC)	$(8.8)
Net NVPC Impact	$53.0
Operations O&M	$32.3
Customer Service / A&G	$29.3
Depreciation/Amortization	$6.6
Non-Income Taxes	$12.0
Add'l Rate Base / COC effects	$29.1
Add'l Other Revenue	$(0.1)
Revenue Growth (other)	$(16.4)
Net Non-NVPC Impact	$92.9
Total Increase Requested	**$145.9**

Q. In the absence of a rate increase, what would PGE's earned ROE be for 2009?

A. As shown in column 1 of PGE Exhibit 201, without a rate increase we would expect PGE's ROE to be approximately 3.4% in 2009.

Q. Does this level of ROE reflect the impact that SB 408 would have on PGE if this rate case were not filed?

A. No. Absent this rate case, we would expect a significant customer refund under SB 408 due to the use of rate making ratios based on prior Commission proceedings (UE 180/UE 188/UE 192). The use of these ratios would result in presumed "taxes collected" under SB 408 far in excess of PGE's projected tax liability for 2009. Under the current SB 408 methodology, this "double whammy" would further reduce PGE's earned ROE in 2009 to approximately 1.0%.

Q. Does PGE's proposal include the revenue requirement effect of any new generating resources for 2009?

A. No. While we currently anticipate that the second phase of the Biglow Canyon Wind Farm (Biglow 2) will be operational in the second half of 2009, we did not include any costs or benefits associated with Biglow 2 in the development of our proposed 2009 revenue requirement. We anticipate recovering net Biglow 2 revenue requirement using the automatic adjustment clause recently approved by the OPUC (See Docket UM 1330, Order No. 07-572).

Q. Are Biglow 1 and Port Westward included in the 2009 revenue requirement?

A. Yes. Thus, Schedule 120, which PGE currently uses to collect the net Biglow 1 revenue requirement approved in UE 188, will be set to zero with the effective date of new rates pursuant to this proceeding.

Q. Does the rate case exclude any capital investments recovered through means other than base rates?

A. Yes. Our 2009 revenue requirement in this case also excludes the costs and benefits of PGE's proposed AMI investment (see Docket UE 189). Since PGE is proposing to use a supplemental tariff to collect the net AMI revenue requirement through 2010, we exclude those costs and benefits in this proceeding.

Q. Please summarize PGE's 2009 revenue requirement.

A. Table 2 below summarizes PGE's 2009 revenue requirement by major category and provides a comparison to Commission-approved amounts from UE 180, UE 188, and UE 192. We also list the PGE testimony that addresses the specific cost categories.

Table 2
(Revenue Requirement Summary in $000s)

Revenue Requirement Category	Currently Approved Amounts	2006 Actual[1]	2009 Test Period	Exhibit Number
Sales to Consumers	$1,561,618	$1,366,738	$1,732,713	200
Other Revenue	19,200	13,426	19,346	200
NVPC	744,834	634,521	806,699	300
Production O&M	86,533	68,048	108,240	400
Transmission O&M	10,245	8,975	11,639	600
Distribution O&M	58,713	63,378	67,910	600
Customer Service	66,638	61,844	73,729	700
A&G	98,314	107,219	120,522	500
Depr. &Amort.	188,473	218,693	195,091	200
Other Taxes	82,690	75,175	94,729	200
Income Taxes	58,963	39,953	68,662	200
Operating Income	$185,414	$102,359	$204,837	
ROE	10.10%	4.46%	10.75%	1000

Q. What is Operating Income in Table 2 above?

A. Operating Income consists of a return to the providers of capital to PGE, both equity and debt. The costs of obtaining capital are discussed in PGE Exhibits 900 and 1000.

Q. How did you develop the 2009 revenue requirement?

A. We developed the 2009 revenue requirement based on PGE's 2008 budget, escalated for inflation and known and measurable changes.

[1] 2006 Regulated Utility Actuals per 2006 Results of Operations Report. Comparable figures for 2007 are not yet available.

Q. What escalation rates did you use to escalate the 2008 budget to 2009?

A. We applied the following escalation rates to the 2008 budget:

- Non-Executive Labor = 4.5% (prorated to reflect expected effective dates of wage increases)
- Executive Labor = 6.0% effective January 1
- Outside Services (CE 21, 26, 41, 49) = 3.3% effective January 1
- Direct Materials (CE 31, 36) = 1.9% effective January 1
- Employee Business Expense (CE 61, 68) = 2.0% effective January 1

Q. Did you adjust PGE's 2009 revenue requirement to reflect previous rate making decisions and other regulatory policies?

A. Yes. We made the following regulatory adjustments, summarized in Table 3 below.

Table 3
(Regulatory Adjustments in $Millions)

Adjustment Item	O&M	Rate Base
Retail Services	$(0.1)	$(0.2)
Charitable Contributions	$(1.1)	
State & Federal Lobbying	$(1.0)	
Memberships and Dues	$(0.1)	
MDCP	$(6.4)	
SERP	$(1.9)	
Category A Advertising	$(0.2)	
Image Advertising	$(1.6)	
MTC	$(0.1)	$(0.5)
Total Adjustments	**$(12.5)**	**$(0.7)**

Q. Please explain these regulatory adjustments.

A. There are nine regulatory adjustments:

- Retail Services: removed $0.1 million of O&M and $0.2 million of rate base per the SB 1149 unbundling rules;
- Charitable Contributions: removed $1.1 million from cost of service;
- State and Federal Lobbying: removed $1.0 million from cost of service;

- Memberships and Dues: removed $0.1 million which reflects the rate making treatment received in UE 180;
- Managers Deferred Compensation Plan (MDCP): removed $6.4 million from cost of service;
- Supplemental Executive Retirement Plan (SERP): removed $1.9 million from cost of service;
- Category A Advertising: removed $0.2 million reflecting the application of 1/8 of 1% of proposed retail revenues, pursuant to OAR 860-026-0022;
- Corporate Image Advertising: removed $1.6 million from cost of service; and
- Metering Technology Corp. (MTC): removed $0.1 million of O&M and $0.5 million of rate base to reflect the treatment of these costs approved in UI 216 (OPUC Order No. 03-518).

Q. Does PGE have any other adjustments to make to the 2009 revenue requirement?

A. Yes. We are developing a list of errata items to the 2009 revenue requirement. These items were not included in this filing due to time constraints. We intend to make an errata filing in late March or early April.

II. Other Revenue

Q. What is PGE's 2009 forecast of other revenue and how does it compare with prior years?

A. PGE forecasts 2009 other revenue of $19.4 million. This compares to UE 180 2007 test year other revenue as filed of $17.7 million and 2007 forecast other revenue of $17.7 million. The 2007 forecast consists of 9 months of actual and 3 months of forecast data.

Q. What are the sources of other revenue?

A. The primary sources of other revenue are rent of electric property, transmission revenues, joint-pole revenues, steam sale revenues, ancillary service revenues, and miscellaneous charge revenues. PGE Exhibit 202 provides the sources and amounts of other revenue, summarized in Table 4 below.

Table 4
(Other Revenue in $000s)

Other Revenue Item	2007 Test Year	2007 Forecast	2009 Test Year
Utility Prop. Rental	$ 6,083	$ 5,310	$ 5,023
Intertie/Other Trans	5,635	6,846	5,903
Late Payment Charges	1,250	697	650
Steam Sales	1,419	1,887	2,413
Other Misc. Revenues	3,341	3,007	5,356
Total Other Revenue	**$17,728**	**$17,747**	**$19,346**

Q. Is PGE proposing new rates for Schedule 300 charges?

A. Yes. PGE Exhibit 1200 describes PGE's proposed rates.

Q. Did you calculate other revenues consistent with PGE's proposed Schedule 300 rates?

A. Yes. We estimated Schedule 300 related revenues of $2.6 million in the test year based on PGE's proposed Schedule 300 rates.

Q. What do you recommend if the Commission does not approve PGE's proposed Schedule 300 charges?

A. We recommend that PGE update its forecast of test year other revenue for such charges to reflect the actual OPUC approved Schedule 300 prices.

Q. In UE 180, the Commission ordered PGE to include $1.4 million in Cal-ISO ancillary service sales in the 2007 test year. Did you include a forecast of Cal-ISO sales in the 2009 test year?

A. Yes. However, we now include these revenues in our forecast of NVPC rather than other revenue, since PGE actually records such sales as an offset to power costs. This also facilitates the inclusion in PGE's power cost adjustment mechanism of any difference between forecast and actual ancillary service sales as required by the Commission in Order No. 07-015. PGE Exhibit 300 provides additional information regarding our 2009 forecast for Cal-ISO ancillary service revenue.

Q. Did PGE make any other adjustments related to other revenue for the 2009 test year?

A. Yes. We adjusted the 2009 forecast of transmission revenues received from Energy Service Suppliers (ESSs). The adjusted amount reflects PGE's current Open Access Transmission Tariff (OATT) rate and the forecasted ESS activity for 2009.

III. Depreciation

Q. What is PGE's estimate for 2009 depreciation expense?

A. We estimate $176.3 million in depreciation expense for the 2009 test year. As previously mentioned, this excludes any depreciation expense related to AMI or Biglow 2. PGE Exhibit 203 summarizes the test year depreciation expense by plant type and provides a comparison to UE 180.

Q. Is PGE proposing a new depreciation study as part of this rate case?

A. No. PGE recently completed a depreciation study (Docket UM 1233) that was approved by the Commission in Order No. 06-581 and clarified in Order No. 07-438. That study was filed in late 2005 and implemented in January 2007. The UM 1233 study updated service life and salvage value assumptions and provided a new methodology for depreciating steam and combustion plant assets. Given the recent adoption of a depreciation study for PGE, we believe that a new study is not warranted at this time. PGE is required to file a new depreciation study five years after the last submitted study or by late 2010.

Q. Did you update any parameters to the existing depreciation study?

A. Yes. We are currently decommissioning the Bull Run project and, as a result, we have obtained more recent and precise estimates. Thus, we updated our estimate of Bull Run decommissioning costs as well as the estimated period of decommissioning relative to the UM 1233 study.

Q. What is the new estimate of Bull Run decommissioning costs and the decommissioning period?

A. We currently estimate that Bull Run decommissioning costs will total $23.7 million. In UM 1233, we estimated these costs would total $17.1 million. We also currently estimate that decommissioning activities will continue through 2012, rather than ending in 2011 as was assumed previously.

Q. What impact do the changes to Bull Run decommissioning have on 2009 test year depreciation expense?

A. 2009 test year depreciation expense increases by $1.9 million as a result of the forecast changes in Bull Run decommissioning costs.

Q. Why have Bull Run decommissioning costs increased from $17.1 million to $23.7 million?

A. PGE's initial estimates of Bull Run decommissioning costs were made prior to the start of the majority of construction-related decommissioning activities. PGE has since completed the demolition of the Marmot dam. Thus, our current estimate is better informed than prior estimates, and reflects significant actual completed work.

In addition, costs for the demolition of the powerhouse, including associated concrete demolition, removal and transportation, decommissioning of Roslyn Lake, and demolition of the Little Sandy dam are significantly higher than previously forecast. We base current estimates of these costs on information received in the RFP for demolition of the Marmot dam. An RFP has yet to be issued for the Little Sandy, Roslyn Lake, and powerhouse decommissioning activity but we expect it to be issued in early 2008.

IV. Amortization

Q. What is amortization?

A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life, but amortization relates to intangible assets, such as computer software and regulatory assets. As with depreciation expense, the unamortized balance of assets generally appears in rate base and earns a return at the allowed rate.

Q. Please summarize PGE's 2009 amortization expense.

A. PGE Exhibit 204 details the total 2009 amortization expense of $18.8 million, which we summarize in Table 5 below. PGE has seven sources of amortization expense for the 2009 test year:

- Intangible Plant;
- Hydro Relicensing Amortization;
- Trojan Decommissioning;
- Colstrip Common Facilities;
- Coyote Major Maintenance Accrual and Amortization;
- Coyote Permit Amortization; and
- Equity Issuance Costs.

Table 5
(Amortization in $000s)

Amortization Item	2007 Test Year	2007 Forecast	2009 Test Year
Intangible Depreciation	$13,251	$14,694	$15,654
Trojan Decommissioning	4,646	5,050	4,646
Other Reg. Debit Amortization	3,943	16,150	2,366
Other Reg. Credit Amortization	$ (2,992)	(7,062)	(3,902)
Total Amortization	**$18,848**	**$28,832**	**$18,764**

Q. Please explain the amortization of Intangible Plant included in PGE's 2009 amortization expense.

A. Total Intangible Plant amortization is $11.1 million which primarily represents the amortization of capitalized software.

Q. Please explain Hydro Relicensing amortization.

A. Hydro Relicensing amortization represents the recognition of annual costs associated with non-construction relicensing projects that have closed to plant in service. Generally, these costs are amortized over the life of the new license. PGE Exhibit 400 further describes these capital costs. Relicensing amortization totals $1.1 million for the 2009 test year.

Q. Are any new intangible property related amortizations included in this filing relative to UE 180?

A. Yes. Pursuant to UE 188, PGE amortizes its investment to upgrade BPA transmission to support Biglow Canyon over a five-year period beginning in 2008 in order to match the expected life of transmission credits to be received by BPA. This adds $2.7 million of amortization expense in the 2009 test year over amounts included in UE 180, but which were previously reflected in rates through UE 188.

Q. Do customers receive the benefit of the BPA transmission credit in the 2009 test year?

A. Yes. The transmission credit is provided as a reduction to NVPC.

Q. Please summarize the outcome from UE 180 regarding Trojan Decommissioning.

A. In Order No. 07-015, the Commission authorized: 1) the annual amount collected in rates be reduced from $14.04 million to $4.65 million, 2) PGE may return to customers $20 million from the Decommissioning Trust, and 3) PGE is authorized to continue collecting funds from customers until decommissioning is complete.

Q. What decommissioning activity has been accomplished since UE 180?

A. PGE completed demolition of the cooling tower in 2006 and the power block buildings in 2007. PGE has started demolition of the containment building and will complete this work in 2008.

Q. Do you recommend any changes in the amount to be collected from customers in this proceeding?

A. No. We performed an analysis of the annual accrual, updated for the latest trust balances, expected rate of return on trust assets, cost estimates, and other parameters. This analysis indicates that no change in the UE 180 approved accrual of $4.65 million is required at this time.

Q. Has the Colstrip Common Facilities amortization changed for 2009?

A. No. We are continuing to amortize this asset as required under prior Commission order.

Q. What is the Coyote Major Maintenance Accrual and Amortization?

A. In UE 93 (OPUC Order No. 95-1216), the Commission approved an accrual and balancing account treatment for Coyote's major maintenance costs. PGE has a long-term service agreement with General Electric to cover major maintenance activities. The major maintenance accrual is based on a multiple-year forecast of major maintenance activities with an accrual estimate designed to bring the balancing account to zero at the end of the multiple-year period. In UE 180, the Commission approved updating the accrual to $2.0 million.

Q. Do you propose to change the Coyote major maintenance accrual for 2009?

A. No. Our analysis suggests that the recently approved $2.0 million accrual will provide for recovery of major maintenance costs over a multiple-year period during which major maintenance activities are expected to occur. An estimate of the 2009 average balance in the balancing account of $7.7 million is also included as a credit against rate base.

Q. Has PGE included a forecast of property sale gains for the test year?

A. No. We continue to support the use of the deferral mechanism for actual utility property sale gains and losses originally approved in UE 115. Since actual gains/losses will be deferred and refunded/collected through a supplemental tariff, we do not include any cost of service reduction in the 2009 revenue requirement to establish base rates.

Q. What are equity issuance fees?

A. Equity issuance fees are the costs associated with issuing additional shares of common equity. As discussed in PGE Exhibit 900, PGE anticipates issuing $200 million of equity in 2009. These fees are estimated at 3.5% of the issue total, or $7.0 million in 2009. Further, equity issuance costs are recorded on the balance sheet as reductions in owner's equity under GAAP and are not expensed for either book or tax purposes.

Q. What is PGE's proposed rate making treatment of equity issuance fees in this proceeding?

A. PGE proposes to treat the equity issuance fees as a regulatory asset and amortize them over a 10-year period beginning in 2009. Thus, we have added $0.7 million in equity issuance expense and we have added a regulatory asset to our rate base to reflect the average unamortized balance in 2009. Finally, to recognize the non-tax deductible nature of these fees, we have added a permanent book-tax difference to the derivation of income tax expense in the test year.

Q. Is PGE seeking Commission approval to account for these fees in the same manner in which it is requesting rate recovery?

A. Yes. PGE seeks Commission authority to record actual equity issuance fees as a regulatory asset and amortize the asset over 10 years. If approved, this would replace the traditional financial accounting treatment of reducing shareholder's equity on the balance sheet to reflect these fees. The requested accounting treatment would align the accounting and rate making treatment of these costs.

Q. What treatment did PGE receive from the Commission when it last issued equity?

A. In PGE's last rate case in which we issued equity (UE 88), PGE included an estimate of equity issuance fees as amortization expense in that rate case. This approach was approved in OPUC Order No. 95-322. PGE included the entire amount within the test years of UE 88 rather than a multi-year schedule of recognition as proposed in this case.

Q. Why is PGE proposing a multi-year recovery schedule for equity issuance fees in this case?

A. We propose this approach here to smooth the impact of the sizable equity issuance offering expected in 2009 and to protect customers from paying too much for these fees in the event that PGE does not file another general rate case for some years.

V. Income Taxes, Taxes Other Than Income

A. Income Taxes

Q. What is PGE's 2009 estimate of income taxes?

A. PGE's 2009 test period income tax expense is $68.7 million. PGE Exhibit 205 details the test year calculations of income tax expense. This compares to 2007 forecast utility income tax expense of $73 million and UE 180 / UE 188 test year approved income tax expense of $59 million. The increase in 2009 test year income tax expense compared to UE 180 / UE 188 primarily relates to increased taxable income due to higher rate base and additional requested equity return in this case.

Q. What methodology did you use to establish estimated income tax expense for the 2009 test year?

A. We use the "stand-alone" method to determine the test year income tax expense. This method uses as inputs only those costs and revenues included in our requested test year revenue requirement to determine the income tax expense for the test year. The Commission has traditionally used this approach to determine the income tax expense in test year rate making.

Q. Does SB 408 (or OAR 860-022-0041) impact your estimate of income taxes for this case?

A. No. SB 408 requires an annual true-up between taxes collected and taxes paid, as those terms are defined in the statute and OAR 860-022-0041. SB 408 itself does not require that test year rate making assumptions about income taxes be changed. For PGE in particular, it does not make sense to attempt to derive test year income tax expense using anything other than the stand-alone approach because PGE's non-utility activity is minimal.

In order to implement SB 408, certain ratios must be established based on rate case results to derive taxes collected for purposes of SB 408.

Q. Have you calculated the updated ratios for SB 408 reflecting PGE's proposed revenue requirement in this case?

A. Yes. The updated net to gross ratio and effective tax rate to be used for SB 408 purposes in 2009 are shown in our work papers.

Q. What income taxes does PGE pay?

A. PGE pays income taxes to the Federal government and the States of Oregon and Montana. PGE also pays income taxes to local government entities such as Multnomah County.

Q. What are the marginal tax rates for PGE?

A. The Federal marginal tax rate is 35.00%, the State of Oregon marginal tax rate is 6.60%, and the State of Montana marginal tax rate is 6.75%. These are the same marginal tax rates used in UE 180 and UE 188.

Q. What is PGE's state composite tax rate for this filing?

A. PGE's composite state tax rate is 5.12%. The rate is a function of the marginal state tax rates and the respective allocation factors of taxable income to different state jurisdictions.

Q. Is the state composite rate different than it was in UE 180?

A. Yes. In UE 180, the state composite tax rate was 6.62%. In this proceeding, we have adjusted the figure downward to 5.12% to reflect the allocation of a portion of PGE's taxable income to Washington state, where there is no corporate income tax. The allocation of taxable income to Washington is the result of power sales at the Mid-Columbia (Mid-C) trading hub, which is located in Washington state.

Q. What is PGE's total composite tax rate for this filing?

A. PGE's total composite tax rate for this filing is 38.33%. It is the sum of the Federal marginal tax rate and the state composite tax rate, less the effect of their interaction, or:

35.00% + 5.12% - (35.00% * 5.12%) = 38.33%

Q. Why did you exclude tax rates from local jurisdictions from the calculation of the composite tax rate?

A. PGE collects Multnomah County Business income taxes through a supplemental tariff to comply with OAR 860-022-0045 and to act as the SB 408 automatic adjustment clause for local income taxes. As such, we do not include an estimate of the costs as part of our revenue requirement in this proceeding.

Q. Did you include state and federal tax credits in your estimate of income tax expense for 2009?

A. Yes. We included $2.0 million of state Business Energy Tax Credit (BETC), $0.1 million of non-Independent Spent Fuel Storage Installation (ISFSI) state pollution control tax credits, and $8.4 million of federal NEPA credits in the estimate of 2009 test year income tax expense. Both the BETC state tax credits and the federal NEPA credits are earned from PGE's Biglow 1 wind project. As previously mentioned, this filing excludes any Biglow 2 costs or benefits. Any tax credits associated with Biglow 2 would be included in a future filing under the renewables automatic adjustment clause (PGE Schedule 122).

Q. Why did you exclude ISFSI state tax credits from the derivation of 2009 income tax expense?

A. ISFSI tax credit amortization is excluded because PGE separately defers ISFSI tax credits pursuant to UM 1186. Since these credits will be refunded to customers separately, we exclude their effects on cost of service in the 2009 test year.

B. Taxes Other than Income & Fees

Q. What is PGE's 2009 estimate of Taxes Other Than Income and Fees?

A. As shown in PGE Exhibit 206, total Taxes Other Than Income are $94.8 million. This compares to the UE 180 total of $85.4 million as filed. The primary sources of the increase from the total in UE 180 are:

- Franchise Fees: from $37.9 million to $43.6 million;
- Payroll Taxes: from $11.6 million to $12.8 million;
- Property Taxes: from $34.7 million to $37.0 million; and
- Other miscellaneous fees: from $1.2 million to $1.4 million.

Q. How did PGE estimate franchise fees?

A. We evaluated the expected level of franchise fees based on estimated 2009 gross revenue in jurisdictions charging franchise fees and applied a 3.5% rate to those gross revenues. Based on OAR 860-022-0040, cities may charge up to 3.5% of gross revenue that will be included in PGE's revenue requirement. Assessments up to 5.0% of gross revenue are allowed, but the incremental fees above 3.5% are charged to customers through a supplemental tariff payable only by customers in the assessing jurisdiction.

Q. Are franchise fees included in PGE's net to gross factor for calculating revenue requirement?

A. Yes. Consistent with the unbundling requirements of OAR 860-038-0200, we separately itemize the impact of our incremental revenue needs on franchise fees in order to directly assign all franchise fees to the Distribution function. The franchise fee rate used to determine this revenue-sensitive cost is 2.51%.

Q. Why have franchise fees increased between the UE 180 rate case and the 2009 test year?

A. Franchise fees have increased due to increased gross revenue in those jurisdictions for which a franchise fee is applicable as a result of approved revenue requirement increases in UE 188 and UE 192. In addition, the impact of PGE's requested increase in this proceeding further increases PGE's forecast franchise fees for the 2009 test year.

Q. Why have payroll taxes increased from the UE 180 rate cases to the 2009 test year?

A. Payroll taxes have increased from $11.6 million in UE 180 to $12.8 million in 2009 primarily as a result of larger payroll due to additional employees and higher wages in 2009 relative to the 2007 test year used in UE 180. The 10.5% payroll tax rate for 2009 is the same rate used to develop estimated payroll taxes in UE 180, but we apply the rate to a larger wage and salary base in 2009.

Q. Why have property taxes increased from the UE 180 rate case to the 2009 test year?

A. Property tax expense increases from $34.7 million in UE 180 to $37.0 million in 2009 primarily due to two factors: a) 2009 property tax expense related to Biglow 1 of $2.0 million due to the addition of this facility since UE 180, and b) increased rate base (in addition to Biglow 1) increases PGE's property tax base in 2009 relative to the 2007 test year in UE 180.

Q. Was the 2009 estimate of Biglow 1 property tax expense developed assuming the Strategic Investment Program (SIP) agreement with Sherman County would be approved?

A. Yes. The SIP was approved in December 2007. As a result, we expect property tax expense for 2009 for Biglow 1 of $2.0 million, or about half of what it would be in 2009 without the SIP.

Q. Did you include the SIP-related costs for 2009 funding of programs in Sherman County?

A. Yes. We included $0.7 million of program-related cost associated with the SIP to fund programs in Sherman County in 2009. These costs are recorded in A&G accounts, however, rather than as property tax expense.

Q. Does your 2009 forecast of property tax expense assume a property tax holiday for Port Westward?

A. Yes, for 2009 we anticipate zero property tax expense associated with the Port Westward generating facility.

VI. Capital Expenditures

Q. What are PGE's total 2009 capital expenditures?

A. As shown in PGE Exhibit 207 and summarized in Table 6 below, PGE forecasts $761 million in total utility capital expenditures for 2009, compared with 2007 forecast capital expenditures of $462 million and UE 180 2007 test year capital expenditures of $232 million.

Table 6
(Capital Expenditures in $Millions)

Type	2007 Test Year	2007 Forecast	2009 Test Year
Production	$ 14.6	$ 15.2	$ 20.8
Transmission	7.0	11.9	7.7
Distribution	121.4	122.3	131.7
Intangible	6.8	4.2	8.1
General	22.8	21.8	21.4
Cap Ex – Operations	172.6	175.4	189.6
Strategic	59.1	286.8	571.1
Cap Ex – Total	**$231.7**	**$462.2**	**$760.7**

Q. How does PGE account for capital expenditures?

A. As PGE spends capital for utility projects, we record it as Construction Work in Progress (CWIP), a non-rate base account. Once the project is completed, PGE moves the capital expenditures (and associated Allowance for Funds Used During Construction) from CWIP to plant in service accounts. Once moved to plant in service accounts, the project becomes part of PGE's rate base with associated depreciation expense and property tax expense recorded in the appropriate income statement accounts.

Q. Are there any significant capital expenditures that you do not expect will close to plant in service during 2009?

A. Yes. We forecast significant capital expenditures for hydro relicensing that we currently expect to close beyond the end of 2009. In addition, we forecast significant capital expenditures for Boardman pollution control equipment that will also close after the 2009 test year. Our work papers detail the capital expenditures in 2008 and 2009 that are expected to close in 2009 (or prior) as well as those capital expenditures that are expected to close after 2009.

VII. Rate Base

Q. What is PGE's 2009 average rate base and what does it include?

A. The total 2009 average rate base is $2,366 million. PGE Exhibit 208 provides the details of the 2009 average rate base, which includes PGE's investment in plant in service, net of Accumulated Depreciation, Accumulated Deferred Taxes, and Accumulated Investment Tax Credits (ITC). In addition, the average rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2009 rate base compare to rate base approved in UE 180 / UE 188?

A. PGE Exhibit 209 shows that the UE 180 / UE 188 average rate base was $2,237 million. Since UE 180 / UE 188, PGE's average rate base has increased by $129 million to $2,366 million, as a result of several factors. The major changes include:

- The completion of the Selective Water Withdrawal project, increasing rate base by $64 million;
- New regulatory debits for equity issuance fees and deposits, increasing rate base by $17 million;
- Higher inventory/fuel stock requirements, reflecting both higher prices for fuel and the need for greater inventories, increasing rate base by $18 million;
- Greater working cash needs as a result of higher operating expenses, increasing rate base by $8 million; and
- Miscellaneous other changes, including depreciation of prior vintage plant in service, capital additions, deferred tax changes, and other changes increasing rate base by $23 million.

Q. How did you develop the estimate of plant in service for the 2009 test year?

A. First, we estimated year-end 2007 embedded plant using actual results as of the end of the third quarter with forecasted closings through year-end. Next, we evaluated 2008 and 2009 capital additions. Certain larger projects were closed based on a specific forecasted closing date. For example, we forecast the Selective Water Withdrawal project to close on March 31, 2009. However, we model most capital additions by evaluating CWIP balances using historical experience. We then applied a forecast closing pattern to CWIP to develop plant in service estimates from 2008 and 2009 capital additions. Our work papers detail the development of 2009 plant in service from forecast embedded plant at year-end 2007.

Q. Are there any new rate base items in 2009 relative to the UE 180 / UE 188 proceedings?

A. Yes. We have two new deferred debit balances in the 2009 test year. The first is Broker Deposits which include collateral PGE's Power Operations group must place against primarily longer-term power purchases. For the 2009 test year, we forecast an average balance of $10.1 million. The Broker Deposit accounts accrue interest, for which we credit customers in the Other Revenue portion of the revenue requirement. The second is deferred equity issuance costs, which average $6.7 million for the 2009 test year.

Q. In UE 188, PGE provided a credit to Biglow 1 rate base to reflect $6 million in funding received by the Energy Trust of Oregon (ETO). Did you include that credit in the development of 2009 average rate base?

A. Yes. In UE 188, it was assumed the accounting treatment for the credit would be as a miscellaneous deferred credit. Since that time, we have determined that the proper accounting treatment of the ETO funds is as a direct offset to the capital costs of Biglow 1. Hence, customers receive the credit as reduced plant in service in 2009.

Q. Has PGE received the funds from the ETO?

A. Yes. PGE received $6 million from the ETO on December 31, 2007.

Q. Does PGE propose a new lead-lag study to update working cash in 2009?

A. No. PGE completed a new lead-lag study in UE 180. Since that study was completed recently, we use the same working cash allowance figure of 5.20% for 2009 as was used in UE 180.

Q. What is the working cash total added to rate base in this filing?

A. Applying the 5.20% working cash factor to the total forecast operating expenses in 2009 of $1,547 million yields the working cash addition to rate base of $80.5 million, which is shown in PGE Exhibit 201.

VIII. Unbundling

Q. Have you unbundled the 2009 revenue requirement pursuant to OAR 860-038-0200?

A. Yes. PGE Exhibit 210 summarizes the results of unbundling the integrated revenue requirement, as required by OAR 860-038-0200, into the required functional areas or revenue requirement categories. Table 7 below summarizes the unbundled revenue requirement for 2009.

Table 7
(Unbundled Revenue Requirement - $Millions)

Production	$1,165.2
Transmission	31.5
Distribution	427.3
Metering	18.5
Billing	32.1
Other Consumer Services	52.6
Ancillary Services	5.6
Public Purposes	Collected by separate tariff
Total	**$1,732.7**

The sum of the unbundled revenue requirement for these services equals the integrated revenue requirement as presented in PGE Exhibit 201.

Q. How did you develop the revenue requirement after unbundling costs and rate base?

A. We used traditional revenue requirement methodology – recovery of cost plus a return on rate base – to calculate the revenue requirement for each unbundled service in accordance with OAR 860-038-0200(9)(d).

Q. How did you unbundle PGE's 2009 expenses and other revenue?

A. We unbundled expenses and other revenue by analyzing each ledger within those categories. First, we determined which ledgers could be directly assigned to one of the functional categories listed in Table 6 above. Second, we evaluated those ledgers that could not be clearly assigned to determine a basis for allocation.

Q. Were most of the expense and other revenue ledgers assigned or allocated?

A. The majority of ledgers have a direct relationship with a single functional area and we assigned these ledgers based on OAR 860-038-0200(9)(b)(A) through (E). The largest category of allocated costs is A&G, which we allocated to the functional areas based on labor dollars for those areas. Other costs, such as property taxes, payroll taxes, income taxes, and the write-off of uncollectible accounts, relate to factors such as net plant, labor, net income, or total revenue. We allocated these costs based on the respective share of those factors per functional area in accordance with OAR 860-038-0200(9)(c)(B)(i) through (ii). For other expenses, such as depreciation and amortization, we "functionalized in the same manner as the respective Plant accounts" – see OAR 860-038-0200(9)(c)(A).

Q. Did you allocate any expense or other revenue to retail or non-utility?

A. No, for two reasons. First, we forecast no labor costs in the ledgers we assigned to retail. As a result, the labor allocation factors will include zero percent to retail. Second, while we forecast labor costs in non-utility, "below-the-line" accounts, these ledgers already receive allocations for corporate governance (i.e., A&G/Support costs) and service providers (i.e., facilities, IT, and print/mail services). Therefore, unbundling A&G (or other support costs) to non-utility ledgers would apply these costs twice.

Q. How did you unbundle rate base?

A. There are two categories of rate base that we evaluated for unbundling: 1) plant in service with associated depreciation reserve, accumulated deferred taxes, and accumulated investment tax credits; and 2) other rate base. For plant in service, we assigned most assets and their associated contra accounts in accordance with OAR 860-038-0200(9)(a)(A) through (F). These assets clearly relate to specific functional areas (e.g., thermal and hydro generating plants, transmission towers and conductors, distribution poles, conductors, substations, transformers, and service drops). Some general and intangible plant was directly assigned, but the majority of these categories consist of many smaller assets without a clear functional attribute so we allocated them based on labor.

Q. How did you unbundle other rate base?

A. We assigned or allocated other rate base using the criteria established in OAR 860-038-0200(9)(a)(G). Specifically, we evaluated other rate base on a ledger-by-ledger basis and directly assigned where applicable (e.g., fuel inventories were assigned to Production). For other categories, we allocated costs on an appropriate basis (e.g., deferred credits related to post-retirement medical and life insurance are allocated based on labor).

Q. Did you assign franchise fees to the Distribution function?

A. Yes. Pursuant to OAR 860-038-0200(9)(c)(B)(i)(IV), PGE assigned franchise fees directly to the Distribution function.

IX. Qualifications

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

A. I received a Bachelor of Science degree in Accounting and Finance from the Ohio State University in 1976. I received a Master of Arts degree in Economics from the University of Tennessee in 1993 and a Ph.D. in Economics from the University of Tennessee in 1995. I have held managerial accounting positions in a variety of industries and have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. Finally, I have worked for PGE in the Rates and Regulatory Affairs department since 1996.

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

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

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
201	2009 Results of Operations Summary
202	Summary of Other Revenue Sources
203	Summary of Depreciation Expense by Plant Type
204	Summary of Amortization Expense
205	Summary of Income Taxes
206	Summary of Taxes Other Than Income
207	Summary of Capital Expenditures
208	Summary of Rate Base
209	Reasons for Changes in Rate Base since UE 180 / UE 188
210	Unbundled Results of Operations Summary

PGE Exhibit 201
2009 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2009 Results At 2007/2008* Base Rates	Change for Reasonable Return	2009 Results After Change for Reasonable Return
	(1)	(4)	(5)
Operating Revenues			
Sales to Consumers (Rev. Req.)	1,586,821	145,892	1,732,713
Sales for Resale	-	-	-
Other Operating Revenues	19,346	-	19,346
Total Operating Revenues	1,606,167	145,892	1,752,059
Operation & Maintenance			
Net Variable Power Cost	806,699	-	806,699
Operations O&M	187,789	-	187,789
Support O&M	193,095	1,156	194,251
Total Operation & Maintenance	1,187,584	1,156	1,188,740
Depreciation & Amortization	195,091	-	195,091
Other Taxes / Franchise Fee	91,061	3,668	94,729
Income Taxes	14,632	54,031	68,662
Total Oper. Expenses & Taxes	1,488,367	58,854	1,547,222
Utility Operating Income	117,799	87,038	204,837
Rate of Return	4.986%		8.659%
Return on Equity	3.405%		10.750%

* 2007 Rates including Port Westward from UE 180 and 2008 UE 188/UE 192 Rates

PGE Exhibit 201
2009 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	2009 Results At 2007/2008* Base Rates	Change for Reasonable Return	2009 Results After Change for Reasonable Return
	(1)	(4)	(5)
Average Rate Base			
Plant in Service	5,173,287	-	5,173,287
Accumulated Depreciation	(2,675,492)	-	(2,675,492)
Accumulated Def. Income Taxes	(265,949)	-	(265,949)
Accumulated Def. Inv. Tax Credit	(271)	-	(271)
Net Utility Plant	2,231,574	-	2,231,574
Misc Deferred Debits	23,755	-	23,755
Operating Materials & Fuel	67,707	-	67,707
Misc. Deferred Credits	(37,755)	-	(37,755)
Working Cash	77,395	3,060	80,456
Total Average Rate Base	2,362,677	3,060	2,365,737
Income Tax Calculations			
Book Revenues	1,606,167	145,892	1,752,059
Book Expenses	1,473,735	4,824	1,478,559
Interest Rate Base @ Weighted Cost of I	77,578	100	77,679
Production Deduction	-	-	-
Permanent Sch M Differences	(13,234)	-	(13,234)
Temporary Sch M Differences	42,599	-	42,599
State Taxable Income	25,488	140,968	166,456
State Income Tax	(779)	7,218	6,439
Federal Taxable Income	26,267	133,750	160,017
Fed Income Tax	830	46,812	47,643
Deferred Taxes	16,036	-	16,036
ITC Amort	(1,456)	-	(1,456)
Total Income Tax	14,632	54,031	68,662

PGE Exhibit 201
General Rate Case - UE 2009 Test Year
Capital Structure / Revenue Sensitive Costs
(000s)

Capital Structure:	**Amount**	**Share**	**Cost**	**Weighted**
Common Equity	N/A	50.00%	10.750%	5.375%
Preferred	N/A	0.00%	0.00%	0.000%
Long-Term Debt	N/A	50.00%	6.567%	3.284%
Total	N/A	100.00%		**8.659%**

Revenue Sensitive Costs:	
Revenues	1.000000
OPUC Fees	0.003125
Franchise Fees	0.025140
O&M Uncollectibles	0.004800
State Taxable Income	0.966935
State Tax @ 5.12%	0.049510
Federal Taxable Inc.	0.917425
Federal Tax @ 35%	0.321099
Total Income Taxes	**0.370609**
Total Rev. Sensitive Costs	**0.400549**
Utility Operating Income	0.599451
Net To Gross Factor	**1.668193**

PGE Exhibit 202
Other Revenue Detail
2006 - 2009 Test Year

Item	FERC Account	PGE Ledger(s)	Actual 2006	Forecast 2007	UE 180 2007	Budget 2008	Forecast 2009	Adjustments	Test Year 2009
Late Payment Interest	450	M38111	625,520	697,384	1,250,000	650,000	650,000		650,000
Misc. Service Revenue	451	M31111	1,393,724	1,636,240	1,021,144	1,721,144	3,088,144	(468,592)	2,619,552
Sales of Water & Water Power	453	M32111	(46,202)	(11,401)	-	-	-		-
Property Rents - Supply Energy	454	M33511	29,531	21,566	-	-	-		-
Rental Rev - Utility Op Prop	454	M33111	37,527	28,089	-	-	-		-
Joint Pole Revenue	454	M33711	4,916,638	4,171,081	4,997,272	4,157,997	3,502,997	555,000	4,057,997
Transformer Rentals	454	M33731	517,140	513,821	521,200	521,200	521,200		521,200
Rent from Electric Prop	454	M33811	639,111	624,981	564,340	424,945	443,571		443,571
Coal Car Rentals	454	M33571	294,494	46,632	-	-	-		-
Other Misc Electric Revenues	456	M34191	531,654	349,716	1,570,689	1,428,880	1,545,693	244,000	1,789,693
Misc Physical Revenues	456	M34819	191,418	195,808	145,490	117,200	117,200		117,200
Steam Sale Revenues	456	M34189	1,506,772	1,886,865	1,419,110	1,688,339	2,413,339		2,413,339
Fish/Wildlife & Rec Facility	456	M34151	16,100	9,976	-	-	-		-
Salmon Springs Hosp Grp.	456	M34322	292,930	310,029	239,800	333,800	333,800		333,800
Rev - Utility Non-KWh Prog	456	M34411	396,864	410,201	354,500	487,000	487,000		487,000
Misc Rev - Supply Energy	456	M34511	83,821.69	-	-	-	-		-
Service Fees - ESS	456	M34575	9,440	9,999	8,900	8,900	8,900		8,900
Late Payment Int - ESS	456	M34577	93	29	-	-	-		-
Non Intertie - Trans for Others	456	M34581	447,819	-	1,847,152	-	-		-
Non Intertie - Trans for Others	456.1	M34591	1,322,621	2,853,387	-	2,589,800	2,589,800	(374,381)	2,215,419
Intertie - Trans for Others	456	M34681	1,028,231	-	3,788,000	-	-		-
Intertie - Trans for Others	456.1	M34691	3,027,922	3,992,868	-	3,688,000	3,688,000		3,688,000
Total Other Revenues			17,263,169	17,747,274	17,727,597	17,817,205	19,389,644	(43,973)	19,345,671

PGE Exhibit 203
Summary of Depreciation
($000)

Property Group	2007 Actual	UE 180 2007 As Stipulated	2009 Test Year
Boardman	6,526	6,704	6,431
Colstrip	7,168	6,863	7,500
Beaver	7,524	7,484	7,877
DSG	144	-	119
Biglow Canyon	1,194	-	10,646
Coyote Springs	6,692	6,697	6,676
Port Westward	4,582	4,578	8,537
Hydro	6,738	5,932	8,232
Transmission	6,801	8,526	8,551
Distribution	89,965	89,874	97,609
General Plant	21,334	22,028	20,726
TOTAL	158,668	158,686	182,904

PGE Exhibit 204
Amortization
2006 - 2009 Test Year

Item	FERC Account	PGE Ledger	Actual 2006	Forecast 2007	UE-180 2007	Budget 2008	Forecast 2009	Adjustments	Test Year 2009
Equity Issuance Fees	4&&	N62&&&	-	-	-	-	-	700,000	700,000
Software Amort	404	N62111	13,856,584	13,542,336	13,251,500	10,844,596	11,103,848	-	11,103,848
Coyote Permits	404	N62121	39,502	39,502	39,502	39,502	39,502	-	39,502
Amort - Hydro Relicensng	404	N62131	1,107,986	1,111,704	1,038,528	1,139,364	3,810,260	-	3,810,260
Trojan Decomm	407	N62452	14,041,000	5,050,086	4,500,000	4,646,000	4,646,000	-	4,646,000
Colstrip Common FERC	407.3	N62321	322,140	322,140	322,140	322,140	322,140	-	322,140
Cat A Amort	407.3	N62325	1,174,923	64,683	-	-	-	-	-
Pelton-RB Amort	407.3	N62328	3,675	-	-	-	-	-	-
Regulatory Amort	407.3	N62329	8,274,139	22,056	-	-	-	-	-
Regulatory Debits	407.3	N62506	125,249	-	-	-	-	-	-
FAS 109 Amort	407.3	N62508	935,512	50,079	-	-	-	-	-
Deferral of Prop Gains	407.3	N62513	275,261	773,622	1,100,000	-	-	-	-
Debit - ARO	407.3	N62515	4,057,055	2,187,744	1,665,594	2,164,080	2,164,080	(2,164,080)	-
SB1149 Amort	407.3	N62516	8,203,666	8,348,124	8,242,566	6,932,363	-	-	-
Deferral of ISFSI Credits	407.3	N62518	4,556,355	2,248,434	2,273,778	2,251,724	(2,011,790)	2,011,790	-
Intervener CUB Fund interve	407.3	N62521	-	-	-	341,420	-	-	-
Intervener Match Fund Amor	407.3	N62522	-	-	-	204,820	-	-	-
Intervener Issue Fund Amort	407.3	N62523	-	-	-	551,170	-	-	-
Coyote Maj Maint	407.3	N62599	4,108,000	2,133,034	2,044,272	2,044,272	2,044,272	-	2,044,272
SB 1149 Deferral	407.4	N62605	(2,348,780)	(2,123,650)	(2,123,528)	-	-	-	-
Amort - Gain UE 115	407.4	N62612	-	(4,221,614)	(1,981,313)	-	-	-	-
Cat A Costs	407.4	N62613	-	-	-	-	-	-	-
Coyote Maj Maint - Amort	407.4	N62614	(1,476,104)	(744,731)	(868,611)	(628,868)	(3,902,226)	-	(3,902,226)
Amort of ISFSI Credits	407.4	N62624	-	-	(7,678,001)	-	-	-	-
SAVE Residual Amort	407.4	N62626	(1,627,132)	(89,578)	-	-	-	-	-
Accretion Expense	411.1	N62701	945,351	891,236	848,958	950,400	950,400	(950,400)	-
Gain from Prop Sales	411.6	N91101	(293,588)	(773,622)	(1,100,000)	-	-	-	-
	411.6	N91331	-	-	2,011	-	-	-	-
Total Amortization			56,280,792	28,831,586	21,577,396	31,802,983	19,166,486	(402,690)	18,763,796

PGE Exhibit 205
Income Tax Summary
Reasons For Change (UE-180/188, 2007/08 Test Years vs. 2009 Test Year)
(000s)

Income Tax Expense	UE-180/188 2007/08 Test Year	2009 Test Year
Book Revenues	1,580,818	1,752,059
Book Expenses (including Depreciation)	1,336,441	1,478,559
Interest Deduction	72,466	77,679
Book Taxable Income	171,911	195,821
Production Deduction	4,017	-
Permanent Sch. M	(9,243)	(13,234)
Temporary Sch. M	50,548	42,599
Tax Taxable Income	126,589	166,456
Current State Taxes	9,360	8,523
State Tax Credits	(1,166)	(2,084)
Net State Income Tax	8,194	6,439
Federal Taxable Income	118,395	160,017
Current Federal Taxes	41,438	56,006
Federal Tax Credits	(8,370)	(8,363)
ITC Amortization	(1,461)	(1,456)
Deferred Taxes	19,161	16,036
Total Income Tax	58,963	68,662
Effective Tax Rate	34.30%	35.06%
Change in Taxes		9,699

Analysis of Tax Change:

Effective Tax Rate Change	0.77%
Book Taxable Income (UE 180/188)	171,911
Increase in Taxes Due to Higher Effective Rate	1,316
Change in Book Taxable Income (2009 vs UE180/188)	23,910
2009 Effective Tax Rate	35.06%
Increase in Taxes Due to Higher Book Taxable Income	8,384
Sum of Tax Impacts	9,699

PGE Exhibit 206
Taxes Other Than Income
2006 - 2009 Test Year

Item	FERC Account	PGE Ledger(s)	Actual 2006	Forecast 2007	UE 180 2007	Budget 2008	Test Year 2009
Payroll Taxes	408.1	Note 1	11,134,400	10,916,003	11,592,430	12,161,793	12,792,769
Property Taxes - Oregon	408.1	N81111	27,039,948	28,206,016	29,794,800	30,893,400	32,650,774
Property Taxes - Washington	408.1	N81211	77,833	52,125	69,600	42,000	34,800
Property Taxes - Montana	408.1	N81311	3,410,334	3,859,740	4,813,880	4,043,160	4,279,200
Franchise Fees	408.1	N83111, N83112	32,368,156	34,984,634	37,897,704	36,298,019	43,560,416
Foreign Insurance Excise Tax	408.1	N83211	-	-	34,200	-	-
Montana Production Tax	408.1	N83611	416,462	451,073	477,000	498,000	462,000
Oregon DOE fee	408.1	N83411	727,715	787,475	720,000	974,239	949,001
Total Taxes Other Than Income			75,174,849	79,257,066	85,399,614	84,910,611	94,728,959

Note 1: Payroll Tax ledgers include N82111, N82211, N82311, N82411, N82511, N82591, and N82599

PGE Exhibit 207
Capital Expenditures, Excluding AFUDC
2006 - 2009 Test Period, Dollars in Millions

Category	2006 Actuals	2007 Forecast	2007 UE 180	2008 Projected	2009 Projected
Production	18.5	15.2	14.6	19.5	20.8
Transmission	6.7	11.9	7.0	6.5	7.7
Distribution	109.0	122.3	121.4	125.0	131.7
Intangible	2.2	4.2	6.8	7.8	8.1
General	14.3	21.8	22.8	20.8	21.3
Capital Expenditures - Ops	150.7	175.4	172.6	179.6	189.6
Relicensing Construction	20.2	49.0	37.5	55.4	21.9
Relicensing Process	4.1	2.5	5.8	2.7	2.6
Port Westward	154.7	16.2	14.0		
Biglow Phase 1	47.8	197.1			
Biglow Phase 2/3		17.1		128.8	376.2
DSG		0.8	1.8	2.1	2.2
AMI	1.0	2.7		18.4	77.9
T&D Expansion Project				36.5	15.1
Other Economic Transmission				3.1	8.5
Other	(0.3)	0.5		1.2	7.1
Boardman Emissions Controls		0.5		5.3	55.0
Boardman Stator Rewind		0.4		2.0	4.6
Capital Expenditures - Strategic	227.5	286.8	59.1	255.5	571.1
Total Capital Expenditures	378.2	462.2	231.7	435.1	760.7

PGE Exhibit 208
Average Rate Base
Test Year based on 12 Months Ending 12/31/09
(000s)

		2009 Test Year
	Plant in Service	5,173,287
Less:	Accumulated Depreciation/Amortization	(2,675,492)
	Accumulated Deferred Taxes	(265,949)
	Accumulated Deferred ITC	(271)
Net Utility Plant		2,231,574
Operating Materials and Fuel Stocks		67,707
Deferred Debits		
	Colstrip Common FERC Adj	2,523
	Def Wheeling Cost 2 Cities	637
	Dispatchable Standby Generation	3,833
	Deposits	10,111
	Equity Issuance Fees	6,650
Deferred Credits		
	Coyote Maint. Accrual	(7,650)
	Injuries & Damages	(5,220)
	Customer Deposits	(3,992)
	Customer Advances	(70)
	Misc. Other	(20,823)
Working Capital		80,456
Average Rate Base		2,365,737

PGE Exhibit 209
Rate Base Comparison
UE 180/UE 188 vs 2009 Test Year
(000s)

	UE 180/188 2007/08 Test Years	Selective Water Withdrawl	Greater Working Cash Requirements	Equity Issue Reg Asset	Higher Inventory Requirements	New Rate Base Deposits	Misc Other	2009 Test Year
Plant in Service	4,850,637	63,975					258,675	5,173,287
Accumulated Depr/Amort	(2,476,708)						(198,784)	(2,675,492)
Accumulated Deferred Taxes/ITC	(230,735)						(35,486)	(266,221)
Net Utility Plant	2,143,195	63,975	-			-	24,405	2,231,574
Other Rate Base	20,934			6,650	17,530	10,111	(1,518)	53,708
Working Cash	72,464		7,991				-	80,456
Average Rate Base	2,236,593	63,975	7,991	6,650	17,530	10,111	22,887	2,365,737

PGE Exhibit 210
Unbundled Results of Operations Summary
2009 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,165,196	31,462	427,296	5,562	18,447	32,118	52,631	1,732,711
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	8,588	5,920	6,557	(5,562)	529	698	2,616	19,346
Total Operating Revenues	1,173,784	37,382	433,853	-	18,976	32,817	55,246	1,752,057
Operation & Maintenance								
Net Variable Power Cost	806,699	-	-	-	-	-	-	806,699
Total Fixed O&M	105,737	10,627	71,425	-	-	-	-	187,789
Other O&M	42,199	5,438	53,622	-	17,027	26,784	49,180	194,250
Total Operation & Maintenance	954,636	16,065	125,047	-	17,027	26,784	49,180	1,188,739
Depreciation & Amortization	65,593	6,857	114,221	-	1,150	3,903	3,367	195,091
Other Taxes / Franchise Fee	25,186	2,134	63,962	-	642	973	1,831	94,729
Income Taxes	26,525	3,800	37,630	-	57	368	281	68,662
Total Oper. Expenses & Taxes	1,071,940	28,856	340,861	-	18,876	32,028	54,659	1,547,220
Utility Operating Income	101,844	8,526	92,992	-	100	789	587	204,837
Rate of Return	8.66%	8.66%	8.66%	N/A	8.66%	8.66%	8.66%	8.66%
Return on Equity	10.75%	10.75%	10.75%	N/A	10.75%	10.75%	10.75%	10.75%
Average Rate Base								
Utility Plant in Service	2,275,830	216,606	2,568,542	-	14,807	51,973	45,530	5,173,287
Accumulated Depreciation	1,097,513	99,160	1,398,102	-	11,004	37,443	32,270	2,675,492
Accumulated Def. Income Taxes	123,255	19,614	108,649	-	2,263	5,741	6,428	265,949
Accumulated Def. Inv. Tax Credit	172	7	92	-	-	-	-	271
Net Utility Plant	1,054,889	97,825	1,061,699	-	1,541	8,788	6,832	2,231,574
Operating Materials & Fuel	60,075	229	7,403	-	-	-	-	67,707
Misc Deferred Debits	10,129	312	3,117	-	10	39	35	13,643
Misc. Deferred Credits	(4,608)	(1,398)	(15,943)	-	(1,380)	(1,384)	(2,931)	(27,644)
Working Cash	55,741	1,501	17,725	-	982	1,665	2,842	80,455
Total Average Rate Base	1,176,227	98,470	1,074,000	-	1,152	9,109	6,779	2,365,736

UE ___ / PGE / 300
NIMAN - TINKER

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Net Variable Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Mike Niman
Jay Tinker

February 27, 2008

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I. Introduction

Q. Please state your names and positions with PGE?

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis. I provide my qualifications at the end of this testimony.

My name is Jay Tinker. I am a project manager for PGE. My areas of responsibility include revenue requirement and other regulatory analyses. My qualifications are included in Section IX of PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial General Rate Case (GRC) forecast of PGE's 2009 net variable power costs (NVPC) and compare this estimate with the 2008 Annual Update Tariff (AUT) NVPC, adjusted for inclusion of Biglow Canyon's effect on NVPC, as approved by the Commission in Order Nos. 07-445 (UE 192) and 07-573 (UE 188). We discuss updates to 2008 AUT parameters such as forward curves, as well as parameter updates and modeling changes, which can occur only in GRC proceedings. We also explain why per unit NVPC have increased by $2.66 per MWh from 2008 to 2009.

Q. What is your GRC net variable power cost estimate?

A. Our 2009 GRC forecast is $806.7 million, based on contracts through January 3, 2008, and forward curves on that same date.

Q. How do you organize the remainder of your testimony?

A. Our testimony includes the following sections:

- Section II: Monet Model;

- Section III: Monet Updates and Model Changes;
- Section IV: Comparison with the 2008 UE 188/UE192 NVPC Forecast; and
- Section V: Qualifications.

II. Monet Model

Q. How did PGE model its NVPC for the 2009 test year?

A. We used our power cost forecasting model, called "MONET" (or Monet).

Q. Please briefly describe Monet.

A. We built this model in the mid-1990s and have since incorporated several refinements. In brief, Monet models the hourly dispatch of our generating units. Using data inputs, such as forecasted load and forward electric and gas curves, the model minimizes power costs by economically dispatching plants and making market purchases and sales.

Monet dispatches PGE resources to meet customer loads based on the principle of economic dispatch. Generally, any plant is dispatched when it is available and its dispatch cost is below the market electric price, subject to operational constraints, such as minimum unit commitment times. Given thermal output, expected hydro and wind generation, and contract purchases and sales, Monet fills any resulting gap between total resource output and PGE's retail load with market purchases (or sales) priced at the forward market price curve.

Q. Has PGE provided additional information on Monet in other dockets?

A. Yes. PGE Exhibit 100 in our 2006 Resource Valuation Mechanism filing (see p. 1, UE 172) and PGE Exhibit 400 in our 2007 test year general rate case (UE 180) describe Monet in greater detail.

Q. How does PGE define NVPC?

A. NVPC include wholesale (physical and financial) power purchases and sales ("purchased power" and "sales for resale"), fuel costs, and other costs that generally change as power output changes. PGE records its variable power costs to FERC accounts 501, 547, 555, 565, and 447. Based on Commission decisions, we include some fixed power costs, such as excise taxes and transportation charges, because they relate to fuel used to produce electricity. We “amortize” these fuel-related costs even though, for purposes of FERC accounting, they appear in a balance sheet account (FERC 151). We also exclude some variable power costs, such as variable operation and maintenance costs, because they are already included elsewhere in PGE’s accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. The “net” refers to net of forecasted wholesale sales.

III. Monet Updates and Model Changes

Q. Does the NVPC section of this proceeding substitute for a 2009 test year AUT filing?

A. Yes. Since this is a GRC proceeding, we include not only the parameter revisions allowed under PGE's AUT (Tariff Schedule 125), but also model changes and updates that are allowed only in a general rate case. The final NVPC update in this proceeding will be the 2009 forecast that we will compare with the 2009 actual NVPC under the provisions of Schedule 126, which implements our Power Cost Adjustment Mechanism (PCAM).

Q. What load forecast do you use in this initial filing?

A. We use the 2009 forecast for cost of service load described in PGE Exhibit 1100. That forecast is approximately 19,965,000 MWh, or 2,279 MWa[1].

A. Updates Allowed under AUT

Q. What updates are allowed under PGE's Schedule 125 (Annual Power Cost Update) Tariff?

A. Schedule 125 states that the following updates are allowed in Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average;
- Projected planned plant outages;
- Forward market prices for both gas and electricity;
- Projected loads;
- Contracts for the purchase or sale of power and fuel;

[1] This is at the bus-bar and differs from load at the customer meter by line losses.

- Changes in hedges, options, and other financial instruments used to serve retail load; and
- Transportation contracts.

Q. Which of these updates do you include in this initial filing?

A. We include all but the forced outage rates. We plan to file an update which includes forced outage rates based on 2004-2007 data by April 1, 2008, consistent with information that would be used in an AUT filing for 2009. By this date, we will have processed the 2007 data needed to complete the outage rate calculations. In this initial filing, we use the same forced outage rates based on 2003-2006 data as we used in UE 192. We will update several of the items included under Schedule 125 as this docket proceeds. These updates will likely include a new Boardman commodity coal contract, the purchase of additional transmission from the Bonneville Power Administration, and updates to the Wells contract and Grant County Settlement Agreement.

Q. Does your update of the Grant County Settlement Agreement significantly impact NVPC in this initial filing?

A. Yes. As discussed in PGE Exhibit 400, the combination of Grant County's needs increasing over time and the expiration of the Wanapum contract at the end of October 2009 reduces PGE's ability to purchase low-cost hydro power from them. Compared to the UE 192 final forecast for 2008, the 2009 forecast for all components of the Grant County Settlement Agreement is for approximately the same amount of power, but with associated costs that are approximately $11 million higher. However, the cost is still reasonable and is less than $45 per MWh.

Q. What schedule in this docket do you propose for NVPC updates?

A. We propose the following schedule for the power cost updates:

- April 1 – remaining plant updates and any errata corrections to the February 27 filing;
- July – update power, fuel, and transportation/transmission contracts; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads;
- September – update power, fuel, and transportation/transmission contracts; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads; and
- November – final updates of power, fuel, and transportation/transmission contracts, and gas and electric forward curves.

B. Changes and Updates Allowed Only in a GRC

Q. What general rate case-only updates and model changes do you propose in this docket?

A. Because this is a general rate case proceeding, we make the following additional updates and modeling changes:

- Updates to reflect the latest Pacific Northwest Coordination Agreement (PNCA) Headwater Benefits study and updated PGE plant H/K factors;
- Updates to thermal plant parameters, including capacities, heat rates, variable O&M costs, start-up costs, minimum commitment times, plant oil usage volumes, and other operational costs and constraints (and their modeling if needed);
- Inclusion of non-running station service when thermal plants are not generating, Biglow Canyon royalty payments, and ancillary service net sales revenues;
- Elimination of the extrinsic value adjustment for the Super Peak Contract; and

- Use of the expected BPA tariff rates and imbalance charges, a day-ahead forecast error component, and modeling of operating reserves to forecast integration costs for Biglow Canyon. These four components replace the $5.50 per MWh integration costs stipulated in UE 188.

Q. Which of these general rate case-only updates and modeling changes do you include in Monet in this initial filing?

A. We include all but the thermal plant parameter updates. We will include GRC-only updates to all thermal plant parameters – capacities, heat rates, variable O&M costs, start-up costs, minimum commitment times, other operational costs and constraints and their modeling (if needed), and plant oil usage volumes in a Monet model update by April 1, 2008.

Q. What is the impact of the general rate case-only updates and modeling changes that have been included in this initial filing on NVPC?

A. These updates and changes in this initial filing increase NVPC by approximately $1.4 million. However, two of the new items in Monet, inclusion of Biglow royalty payments, and net ancillary service sales revenues, are reclassifications[2] to NVPC from other categories (O&M and Other Revenues), rather than changes to our modeling. Aside from these two reclassifications, updates and modeling changes increase NVPC by approximately $1.2 million.

1. Pacific Northwest Coordination Agreement Update

Q. Please describe the changes you made based on the Pacific Northwest Coordination Agreement (PNCA) study.

[2] Net ancillary service revenue was included in Other Revenues in UE 180. Biglow royalty payments were included in O&M in UE 188.

A. Under the PNCA, the Northwest Power Pool conducts a 70-year regulation study called the Headwater Benefits Study (Study), based on a regulation model, whose objective function is to maximize the firm energy load-carrying capability of the Northwest system as a whole. This model considers the loads and thermal resources of regional entities, as well as hydro resources. The model produces a simulated regulation of 70 years under historical streamflows, which we then use, with a set of adjustments, to develop the average hydro energy inputs to Monet. For this filing, we updated to the 2006-07 Study to establish base average expected outputs for our hydro resources. We then adjusted these base figures in essentially the same way as in previous filings. The adjustments we made include running the PNCA model in continuous mode and using the same basic adjustments performed to develop our UE 180 hydro energy inputs to Monet.

Q. What impact do these PNCA-related changes have on your 2009 NVPC forecast?

A. The net impact of updating the PNCA study is a decrease in NVPC of $2.7 million.

2. Hydro Plant Performance

Q. How do the hydro plant performance factor updates impact the Monet forecast?

A. The primary updates are to the H/K factors, which translate hydro flows into electricity generation. The changes in these factors, compared to a 2007 (UE 180) base, were immaterial, except for Pelton. We updated the Pelton H/K factor from 11.0 kW/cfs to 10.7 kW/cfs, resulting in a NVPC increase of approximately $0.6 million.

3. Thermal Plant Non-Running Station Service

Q. Please describe thermal plant non-running station service.

A. When they are not running, our thermal plants acquire most of their internal electric power needs, or station service, by means of backfeed from the 230-kV or 500-kV transmission system. In the case of backfeed from BPA's system, which applies to Coyote Springs, Beaver, and Boardman when drawing from BPA's Slatt Substation, we return the energy to BPA later, resulting in a cost to PGE to supply this return energy. In the case of direct interconnection to PGE's system, such as at Port Westward, the station service is an additional load that we do not include in the load forecast used by Monet. In the case of Colstrip Units 3 and 4, the non-running station service is fed either by the unit that is still operating or back-fed from BPA or NorthWestern Energy. Either way, the non-running station service load is an additional load that must be served, resulting in additional NVPC. The cost to supply non-running station service load, whether by backfeed, direct interconnection, or other means, is part of PGE's cost of providing service and is not reflected elsewhere in PGE's 2009 test year revenue requirement. For the 2009 test year, we forecast approximately $1.9 million for station service. We model this dynamically in Monet as a function of average station service load, maintenance, forced outage rates, and estimated economic dispatch.

4. Biglow Canyon Royalty Payments

Q. What is the basis for your forecast of royalty payments related to Phase 1 of the Biglow Canyon wind farm?

A. Contracts specify 2007 rates per MWh, with inflation index escalators on January 1 of each year, for both land owners and the original site developer, Orion Energy LLC. In our Monet forecast, we multiply these rates by expected Biglow Canyon output. We will update these inflation indices during the GRC process.

Q. Did you use this same approach in UE 188, the first proceeding related to Biglow Canyon?

A. Not precisely. In UE 188, we used the same approach to calculate the cost of royalty payments - contractual rates multiplied by expected output. However, in that docket, we included these costs in O&M expenses, rather than in NVPC. We subsequently determined that it is more appropriate to include them in NVPC, given that they vary with output.

5. Sales of Ancillary Services

Q. What is the basis for your estimate of net revenues from the sale of ancillary services?

A. We base our 2009 forecast of $0.76 million on actual 2007 sales of reserves to the California Independent System Operator (Cal-ISO), net of grid management charges imposed by the Cal-ISO on those sales.

Q. Why do you include these net revenues in NVPC?

A. In Order No. 07-015 (Docket UE 180), the Commission directed that PGE credit customers with $1.43 million per year for these net revenues through Other Revenues. (Order No. 07-015 at 15-16) Dockets UE 188 and UE 192 did not address Other Revenues. Therefore, PGE made no change to the annual $1.43 million credit through Other Revenues for the 2008 test year associated with these dockets. However, this is a general rate case, which allows for revision of Other Revenues. In this filing, we eliminate the $1.43 million from Other Revenues, replacing it with the inclusion of the updated estimate of $0.76 million in NVPC. It is more appropriate to include this credit in NVPC since we record actual ancillary services revenue in NVPC, and because Order No. 07-015 directs that variances between estimated and actual net ancillary service sales revenues be included in the annual Power Cost Variance calculation, implemented through PGE's Tariff Schedule 126.

Q. Why is it appropriate to include your $0.76 million figure in the 2009 NVPC forecast?

A. Net ancillary service sales revenue data for use in PGE's 2009 NVPC forecast should meet two criteria. They should reflect California's measures to reduce reserve prices, and they should be from an entire year, as sales vary across months. Only the data from calendar year 2007 meet both criteria. Our estimate of $0.76 million is based on our actual experience in 2007.

PGE began selling reserves to the Cal-ISO in June 2005. The $1.43 million figure that the Commission used in Order No. 07-015 was based approximately on the first 12 months of activity – mid-2005 through mid-2006. Subsequent to that period, California took measures to decrease reserve prices. These measures have been effective, thereby reducing PGE's net revenues from the sale of reserves. We expect these measures to continue in the future, possibly further reducing PGE's net sales revenues.

6. Capacity Contract Adjustment

Q. What changes did you make for the Super Peak capacity contract?

A. We changed the extrinsic value adjustment from $1.384 million to zero.

Q. Why do you make this change?

A. We remove the Super Peak extrinsic value adjustment because it is inconsistent with our Monet net variable power cost modeling.

Q. Why is this one adjustment inconsistent with your Monet forecast of net variable power costs?

A. Monet forecasts the operations and associated values of all of PGE's owned and contractual power supply resources for the 2009 test year. Many of these forecasts will turn out to be incorrect. However, we do not make individual resource adjustments to reflect guesses of how Monet's forecasts might differ from actuals. Incorporating only one aspect of the impact of forecasting uncertainty on PGE's power costs (i.e., the possible extrinsic value of the Super Peak contract) would effectively be cherry picking one aspect of uncertainty which might lower costs, while ignoring other aspects of uncertainty which might raise costs. This is more appropriately considered in the stochastic power cost modeling review in Docket UM 1340.

Q. If the individual resource (forecast vs. actual) differences sum so that overall NVPC are much higher or much lower than the Monet test year forecast, how are these overall differences passed through to customers?

A. If there are differences between actual overall NVPC and the Monet forecast, PGE's PCAM (Tariff Schedule 126) passes them through to customers (subject to a deadband, sharing ratios, and an earnings test). For example, PGE's 2007 actual NVPC were lower than the forecast, and PGE will pass part of the difference back to customers through Schedule 126.

7. Wind Integration

Q. How did you estimate wind integration costs?

A. In this initial filing we include our latest estimates for four Biglow Canyon wind integration components. We plan to purchase within-hour integration and imbalance services from BPA. We estimate $1.8 million or $4.39 per MWh for these two components combined. We also explicitly model the opportunity cost of carrying operating reserves for Biglow, which is equivalent to approximately $0.12 per MWh. Finally, we include our current estimate for other integration costs, $0.99 per MWh. These other integration costs include the cost of day-ahead forecast errors. The charges for the four components sum to $5.50 per MWh.

Q. Please discuss the services you intend to purchase from BPA.

A. We plan to purchase integration service from BPA, under a tariff whose rates are not yet final since they are the subject of an on-going BPA rate case. We expect that these rates will be in place beginning in October 2008, thereby affecting the entire calendar 2009 test year. The proposed BPA tariff has two main components – a fixed per MW-month charge and a charge that applies if actual output across an hour is different (beyond a small deadband) from what PGE schedules. BPA will deliver to PGE the scheduled amount, but will then charge a 10% premium above market for power needed to make up the difference between scheduled and actual generation in the case of lower than scheduled output. In the case of higher than scheduled generation, BPA will deliver the scheduled amount and pay PGE for the excess, but at a rate of 10% below market. PGE's current expectation of the monthly demand charge is $0.81 per kW-mo. We also estimate that the effective cost of BPA's treatment of differences between power scheduled and power actually produced (on an "average across each hour" basis) will be approximately $1.47 per MWh during the 2009 test year. As stated above, these two components then sum to approximately $1.8 million, or $4.39 per MWh.

Q. Is the Biglow Canyon Phase 1 output forecast in this initial filing the same as your UE 188 forecast?

A. Yes. The annual figures are slightly different only because 2008 is a leap year. If we receive more information, we will update the Biglow Canyon Phase 1 forecast as appropriate during the GRC process.

IV. Comparison with 2008 UE 188 / 192 NVPC Forecast

Q. Please restate your initial 2009 GRC NVPC forecast.

A. The initial forecast is $806.7 million.

Q. How does the 2009 GRC forecast compare with the UE 188 / 192 2008 forecast (including Biglow Canyon Phase 1) approved in Commission Order Nos. 07-575 and 07-445?

A. Based on PGE's final updated (Biglow inclusive) Monet run for the 2008 test year, the 2008 forecast is $744.8 million, or $37.74 per MWh. The 2009 forecast is $806.7 million, or $40.40 per MWh.[3]

Q. Are the 2008 and 2009 NVPC forecasts comparable?

A. Yes. They differ only by the inclusion of net revenues for sales of ancillary services and Biglow Canyon royalty payments in the 2009 forecast. The combined effect of these two factors increases NVPC only by approximately $0.2 million. As stated earlier in our testimony, these are not revenue requirement increases. They are simply reclassifications from Other Revenues and O&M.

Q. What are the primary factors that explain the increase in the 2009 forecast (over the 2008 forecast)?

A. As Table 1 shows, the approximately $62 million increase is due to several factors:

[3] These calculations are based on bus-bar cost of service load and include the fact that the 2009 load forecast is 33 MWa higher and that 2008 is a leap year.

Table 1
Factors in Power Cost Differences ($Million)

Element	Effect
Hydro Cost and Performance	$13
Coal Cost and Performance	29
Gas Cost and Performance	10
Gas Financials	-17
Contract Costs	-10
Market Purchases to Fill Contract Deficit	21
Market Purchases for Load Increase	14
Other (Net)	2
Total	**$62**

We expect slightly less hydro production in 2009, but purchased hydro costs increase substantially, primarily because costs under the Grant County Settlement Agreement increase substantially. Coal-generated output decreases in 2009 with longer planned maintenance outages at both Boardman and Colstrip. Coal costs also increase, primarily because the current commodity coal contract to supply Boardman will expire at the end of 2008 and we expect a significant increase in costs under a new coal contract. The cost of gas-generated production will increase because of somewhat higher gas costs. However, this is off set by the increased hedging effect of gas financials we currently own. Contract costs for 2009 are lower on a per MWh basis, but market purchases are needed to make up for a lesser quantity of contract MWh. Market purchases are also necessary to serve the approximately 33 MWa increase in cost-of-service loads from 2008 to 2009.

V. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

Q Does this conclude your testimony?

A. Yes.

UE ___ / PGE / 400
QUENNOZ - LOBDELL

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Fixed Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Quennoz
James F. Lobdell

February 27, 2008

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I. Introduction

Q. Please state your names and positions with PGE?

A. My name is Stephen Quennoz. My position at PGE is Vice President, Supply. I am responsible for all aspects of PGE's power supply generation and for decommissioning the Trojan nuclear plant.

My name is James F. Lobdell. My position is the Vice President, Power Operations and Resource Strategy. I am responsible for PGE's Power Operations group. I have responsibility for the activities necessary to ensure adequate power supply to meet retail load. In addition, I am responsible for Integrated Resource Planning (IRP) to ensure an adequate power supply to meet future retail load.

We provide our qualifications at the end of our testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to support Operations and Maintenance Costs (O&M) and rate base-related costs associated with PGE's long-term power supply resources for both owned plants and contracts. We also update information PGE provided in Section III of PGE Exhibit 300 in Docket UE 180 (PGE Exhibit 403 in this filing) concerning the relicensing of our hydro facilities.

Q. What is the primary goal of PGE's plant related activities?

A. The primary goal of our plant related activities is to maintain high levels of plant availability and system reliability, as the composition of our production resource mix evolves over time. High availability allows our power operations group to dispatch plants whenever their variable costs are less than the market price of power, thereby keeping net variable power costs low for customers. High system reliability ensures that we meet our obligation to serve on-demand customer loads.

Q. Does your testimony explain how you are achieving this primary goal?

A. Yes. In Section III, we discuss activities that maintain the reliability of our aging power plants. When longer planned maintenance outages are necessary, we schedule them at times of the year when power prices are lowest. Continued good plant availability directly impacts the test year net variable power cost forecast presented in PGE Exhibit 300.

Q. How do you organize your testimony?

A. We organize our testimony into the following sections:

- Section I: Introduction
- Section II: Resource Summary (Plants, Power Contracts, and Transmission)
- Section III: Plant and Power Operations (O&M, FTEs and Capital Additions)
- Section IV: Hydro Relicensing Update
- Section V: Qualifications

II. Resource Summary

A. Power Supply Resources

Q. Have you prepared an exhibit that shows all of PGE's power supply resources for the 2009 test year?

A. Yes. PGE Exhibit 401 lists PGE's supply resources and their capacity and expected energy values.

Q. Has PGE recently provided detailed information about its most recent plant additions, Port Westward and Biglow Canyon (Phase 1)?

A. Yes, in UE 180, we provided information on Port Westward and also on the other resources that we acquired through our 2003 Request for Proposals, with the exception of Biglow Canyon. In UE 188, we provided information on Biglow Canyon.

Q. Which of PGE's long-term power supply resources have changed significantly since the UE 188 and UE 192 proceedings?

A. The Grant County Settlement Agreement (Settlement Agreement) and our dispatchable standby generation resources have changed significantly since these most recent power cost-related proceedings.

Q. How has the Grant County Settlement Agreement changed?

A. This agreement covers PGE's rights and obligations related to two hydro facilities, Priest Rapids and Wanapum. PGE has or had contracts for percentage output shares of the Priest Rapids and Wanapum plants, which expired or will expire on October 31, 2005, and October 31, 2009, respectively. Extensive negotiations with Grant County PUD resulted in a Settlement Agreement concerning various parties' payment obligations and rights to power from Priest Rapids and Wanapum after the 2005 and 2009 contract expiration dates. During a transition period through October 2009, we will continue to pay a percentage share of Wanapum's costs in exchange for an equal percentage share of the output. The Settlement Agreement also includes other products – surplus firm, conversion, meaningful priority, and displacement – based in part on Grant County's needs, which will grow over time, and on a 1998 FERC ruling. Given Grant County's growing needs and the expiration of the Wanapum contract during the 2009 test year, the Settlement Agreement reflects a reduction in PGE's rights to purchase low-cost power from these two hydro resources. These lower volumes are reflected in our NVPC forecast discussed in PGE Exhibit 300.

Q. Has PGE's dispatchable standby generation capacity increased in recent years?

A. Yes. We now have 22 dispatchable standby generation projects that provide 43 MW of reliable diesel-fired capacity at peak times. This is a substantial increase from the end of 2005, at which time we had completed 15 projects with combined capacity of 26 MW. We expect to add approximately 10-15 MW of dispatchable standby capacity per year over the 2008-2009 period.

Q. What other benefits do the dispatchable standby generators provide, besides peak-load capacity?

A. Because we can start these resources within ten seconds, they provide a block of reserve power for our system. Reserve requirements for thermal and hydro resources are 7% and 5%, of which half must be spinning. Dispatchable standby generators do not qualify as spinning reserves, but they can help provide the remaining operating reserves - 3.5% for thermal, 2.5% for hydro. Thus, the existing 43 MW of dispatchable standby generation can provide non-spinning reserves for more than 1,200 MW of thermal resources or more than

1,700 MW of hydro resources. We include this non-spinning reserve capability in our NVPC modeling. Our NVPC updates during this proceeding will include revised estimates of average dispatchable standby capacity during the 2009 test year.

In addition to providing non-spinning reserves, dispatchable standby generation, when operating, acts like a demand response program - it supplies most or all of dispatchable standby generation customers' loads, removing these loads from the grid. Finally, dispatchable standby generation adds fuel diversity to PGE's resource mix.

Q. Why does the utility need capacity resources?

A. Capacity resources enable a utility to meet its obligation to provide safe and reliable power to customers. Specifically, these resources help meet customer loads, sometimes under conditions which may be extreme, but of short duration. For example, we might have an immediate need for power if one of our major thermal resources suddenly went off-line, or if loads increased rapidly due to an extreme temperature event. In other words, capacity resources provide the ability to "keep the lights on."

Q. What criteria does PGE use in its selection of capacity resources?

A. We consider two primary criteria. The first and most important criterion is that the resource must be reliably dispatchable on demand. The second most important criterion is low fixed costs for customers. Possible margins are not an important criterion because capacity resources generally have high variable costs, making them uneconomical to run except in emergencies and other extreme events.

Q. Do capacity resources selected by PGE have to compete with other alternatives?

A. Yes. For example, we selected two PPM option contracts in the 2003 RFP process related to our 2002 IRP. These contracts competed with nine other capacity resource bids and were part of the IRP Final Action Plan acknowledged in OPUC Order No. 04-375.

Q. What are PGE's plans for major new power supply resources?

A. We plan to complete Phases 2 and 3 of our Biglow Canyon wind farm in 2009 and 2010. We anticipate recovering net Biglow 2 and 3 revenue requirements using the automatic adjustment clause recently approved by the OPUC (See Docket UM 1330, Order No. 07-572).

B. Transmission Resources

Q. Why does PGE need long-term transmission contracts?

A. PGE is a transmission dependent utility. Therefore we must purchase adequate transmission capacity from third-party providers to reliably and cost-effectively meet our customer load obligations. Our transmission dependence stems from our need to transmit energy from remote generating resources, long-term contractual delivery points, and short-term markets to meet our customers' needs. Even with efficient new resources such as Port Westward, PGE can sometimes lower costs for customers by purchasing energy on the wholesale market and then arranging to deliver that energy to our service territory.

Q. What major transmission agreements does PGE have with BPA?

A. PGE has four major transmission agreements with BPA. These are:

- Integration of Resources (IR) agreement,
- Point-to-Point (PTP) agreements,
- AC/DC Intertie agreement (also involves PGE Transmission Services), and
- Montana Intertie agreement.

Q. Please describe the IR and PTP agreements.

A. The IR agreement allows PGE to deliver power from our thermal resources, the Mid-Columbia hydros, and a system (capacity) purchase from Spokane Energy to the PGE system. This IR agreement, which expires on December 31, 2009, also allows PGE to deliver power from these resources to John Day or Big Eddy, the head of the AC and DC interties. PGE Exhibit 402 summarizes the delivery capacities.

The PTP agreements provide PGE with firm transmission rights across BPA's transmission system from one point of receipt (POR) to one point of delivery (POD). This transmission can also be used non-firm from alternative PORs to alternative PODs when transfer capacity is available. PGE Exhibit 402 summarizes the current agreements, all of which are in force at least into 2010 and have rollover rights.

Q. Please describe the AC/DC Intertie Agreement.

A. PGE's AC/DC Intertie rights are defined in the BPA/PGE Intertie Agreement. Under this Agreement, PGE Transmission Services (PGE Transmission) controls 850 MW of southbound rights on the AC line from John Day to the California-Oregon border (COB). PGE's power operations[1] group has purchased 200 MW of rights on the southbound AC line that it uses to sell excess power in California. This 200 MW purchase was pursuant to PGE Transmission's open access tariff. The power operations group also has rights to 100 MW of DC Intertie pursuant to an exchange of AC for DC (resulting in a decrease in AC rights from 950 MW to 850 MW) under the BPA/PGE Intertie Agreement.

Q. Please describe the Montana Intertie agreement.

A. This agreement represents an exchange of firm transmission rights between PGE and BPA that enables PGE to transmit energy from our share of Colstrip Units 3 and 4 to our service territory. The Montana Intertie agreement provides PGE with 280 MW of firm transmission on BPA's line from Townsend to Garrison in exchange for BPA rights of firm transmission on the Colstrip line from Townsend to Broadview, which is located approximately midway between Townsend and Garrison.

Q. Do you discuss the O&M expenses and capital additions associated with PGE's owned transmission resources?

A. No. Mr. Hawke discusses these transmission requirements in PGE Exhibit 600.

[1] PGE's power operations group is also called "PGE Merchant" to distinguish it from PGE Transmission under FERC's open access policies.

III. Plant and Power Operations O&M and Capital Additions

A. Plant O&M

Q. Please summarize PGE's plant and power operations-related O&M costs from 2007 to the 2009 test year.

A. Table 1 below provides plant O&M costs from 2007 to 2009.

Table 1
Summary Plant-Related O&M Statistics ($millions)

	2007 Forecast(1)	**2008 Budget**	**2009 Test Year**
Hydro O&M	$9.9	$11.8	$14.3
Coal O&M	31.1	31.2	37.5
Gas O&M*	18.4	25.9	27.2
Wind O&M	0.0	5.2	5.4
General Plant O&M	4.5	5.2	5.7
Power Operations O&M	12.3	14.1	16.2
Totals	$76.2	$93.5	$106.3

** Adjusted for the Coyote Springs O&M accrual.*
(1) 9 months actual +3 months forecast

Q. What are the primary drivers for the changes in O&M in Table 1?

A. The primary drivers are:

- Port Westward is on-line for a full year beginning in 2008, rather than the 6.7 months in 2007. This increases O&M by $4.2 million over the 2007 forecast, although it was effectively included in retail rates through UE 180/184.
- There is a $2.2 million increase at Beaver in 2008 for several reasons, including an extended planned outage to perform a turbine generator inspection, a generator rewedge, and to repair the demineralizer roof. We expect similar expenditures during the 2009 planned outage on the other Beaver turbines.
- In 2009, at Colstrip there will be an overhaul and chemical clean, work on the paste plant, as well as increased mercury controls, which will cost approximately an additional $3.2 million over 2008.

- Boardman has several maintenance procedures scheduled in 2009, including replacing burner barrels, work on the north feed pump and pulverizer pivot brackets, and a boiler acid cleaning. These tasks will cost nearly $3.0 million.
- Biglow Canyon (Phase 1) is included in 2008 and 2009, but was not in rates in 2007. Its 2009 O&M costs are $5.4 million, which were effectively covered in UE 188.
- By 2009, there is a $3.2 million increase to fulfill new hydro licensing requirements.
- By 2009, cost increases for various maintenance jobs related to preservation of our hydro facilities and decreases from the closure of Bull Run net to an increase of $0.9 million.
- By 2009, power operations and dispatch costs increase by $1.9 million due to operating in a more complex and regulated environment, including the provisions of FERC Orders 890 and 890-A.
- Increases in the IT allocation and the cost of maintaining existing software for power operations sum to $0.8 million by 2009.

We provide detailed explanations of plant and power operations O&M cost changes below.

Q. Do PGE's aging plants require more maintenance?

A. Yes. We list several examples of longer outages above and discuss them in detail later in this section. These longer outages require more labor and materials and thus their O&M costs are higher than for our newer plants.

Q. Has the recent escalation of raw material prices had an effect on O&M costs?

A. Yes, somewhat. The prices for raw materials have increased due to intense demand, related to rapidly growing sectors of the global economy, the weak U.S. dollar, and continued offshore capital investment. Also leading to higher material costs are the impacts of escalating oil prices and the shortage of skilled labor that is working through the supply chain.

Q. Please discuss the changes in coal plant O&M expenditures shown in Table 1 above.

A. The 2009 budget is approximately $6.4 million higher than in 2007, primarily due to extended outages at both Boardman and Colstrip.

- Colstrip Unit 4 will be off-line for 55 days for an overhaul and chemical clean, which we expect to cost approximately $2.7 million. An additional $0.5 million at Colstrip is primarily for increased mercury control costs as well as additional employees to work on the paste plant.
- At Boardman, we will have a planned outage of 61 days to accomplish several maintenance tasks – replace burner barrels, replace north feed pump internals, perform a boiler acid cleaning, and work on the pulverizer pivot brackets. The $3.0 million is primarily for contract labor and outside services to complete these tasks.

Q. Why do 2008 budgeted gas O&M expenditures increase by approximately $7.5 million compared to the 2007 forecast?

A. Port Westward's O&M expenses will increase because the plant will be on-line the entire year, rather than just 6.7 months as in 2007. On a "per month in service" basis, 2008 budgeted expenses of $9.2 million are almost the same as the 2007 forecast of $5.0 million. Beaver's expenditures increase by approximately $2.2 million for several reasons, including a ten week outage for a combustion turbine generator inspection, a generator to rewind, and repair of the demineralizer roof. There were also unexpected cost savings in 2007 at Beaver, where the plant was on economic standby more than budgeted. These unexpected savings helped management to coordinate with the power operations group to extend maintenance outages and reduce overtime labor. Preventive maintenance at Coyote also increases by $0.5 million. In 2007, PGE was able to successfully negotiate coverage of certain budgeted maintenance items under the Long-Term Service Agreement (LTSA), but we do not expect this to recur in 2008 and beyond.

Q. Why do gas O&M expenditures increase in the 2009 test year forecast by approximately $1.3 million compared to the 2008 budget?

A. This increase is mostly due to inflation and wage escalation. In addition, there is an approximate $0.3 million increase at Beaver related to inspections in 2009. In 2008, we budget $0.7 million for a combustion turbine generator inspection, which will not occur in 2009. However, in 2009 we budget $1.0 million for an inspection of the Beaver-Kelso pipeline, which is required by FERC. These two net to the additional $0.3 million increase in 2009 at Beaver.

Q. Please explain the Coyote Springs LTSA.

A. PGE has an LTSA with General Electric for maintenance at the Coyote Springs plant. Under the LTSA, certain tasks have to be done after a specified number of operating hours. This results in O&M costs which vary considerably from year to year. The budgeted change from approximately $0.6 million in 2008 to $3.9 million in 2009 is an example of this variability. However, PGE has an accrual mechanism in place that smoothes this variability. We collect approximately $2.0 million each year, which goes into a balancing account.

Actual expenditures are netted against the balancing account. We implement this levelized $2.0 million annual collection amount in the test year revenue requirement by reversing the $3.9 million O&M amount in amortization expense. This effectively substitutes the levelized $2.0 million annual collection amount for the $3.9 million O&M amount, thereby reducing the revenue requirement by $1.9 million. Table 1 reflects the $2.0 million figure for each year.

Q. Why does wind O&M expense only begin in 2008?

A. Wind O&M expense is entirely for Phase 1 of PGE's Biglow Canyon (Biglow) wind farm, which entered retail rates on January 1, 2008, per Order No. 07-573 in Docket UE 188.

Q. Why does the 2008 O&M portion of the Biglow revenue requirement appear lower than that approved by the Commission in Order No. 07-573?

A. The 2008 budget figure, which is consistent with that for the 2009 test year, is approximately $1.2 million less than the O&M portion of the 2008 revenue requirement approved by Order No. 07-573. This is primarily because we reallocated property insurance and royalty payments. In UE 188, these costs were classified as O&M. For this filing, we believe that we should include Biglow-specific property insurance as part of insurance and royalty payments in net variable power costs, as discussed in PGE Exhibit 300. Overall O&M costs have not materially changed.

Q. Please explain the changes in hydro O&M expenditures shown in Table 1.

A. The increase in hydro O&M from 2007 to 2009 is approximately $4.4 million. Most increases in expense fall into two general categories, new licensing requirements and on-going maintenance projects for the preservation of facilities. Approximately $3.2 million of the cost increase is to meet new license requirements at several of our hydro facilities.

At Round Butte, new license requirement costs increase by $1.8 million from 2007 to 2009 ($0.5 million in 2008 and $1.3 million in 2009). In 2008, at Round Butte we are obligated to provide annual funding to Jefferson County for law enforcement support of the project lands, including Lake Billy Chinook, maintain the United States Forest Service network of roads, and maintain and protect significant historic properties within the project boundary. In 2009, increased expenses are due to other license requirements, including Lamprey studies, fish pathways and rock scaling.

At the Faraday facility, a $0.4 million increase is due to several factors, including a FERC-required inspection, increased operator training, and the development of a Site Usage Plan for the West Side Hydro facilities. A $0.2 million increase at Sullivan is for a fish biologist contractor and other professional services. These costs are tied to additional required testing and monitoring of fish following the completion of the fish passage improvements.

Additionally, there is a $1.6 million increase for on-going maintenance projects for the preservation of facilities including Oak Grove and North Fork. The increase at North Fork includes inspection and repair of the migrant fish pipe, which moves fish around the powerhouse, and maintaining surrounding Forest Services roads to fulfill licensing obligations. Also, there is a $0.7 million decrease due to the decommissioning of the Bull Run facility. With the removal of the Little Sandy dam and the wood flume, power production at Bull Run will cease in mid-2008.

Q. General production O&M changes by $1.1 million from 2007 to 2009. What are the reasons for this increase?

A. The primary drivers for the increase from 2007 to 2009 are:

- $0.3 million for consultants, primarily to help develop NERC/WECC compliance procedures;
- $0.1 million increase for the newly established Reliability Centered Maintenance (RCM), described below in "Generation Excellence Initiative";
- $0.6 million for additional labor to oversee hydro and wind projects, including hydro licensing, the Selective Water Withdrawal project, and succession planning; and
- $0.1 million for miscellaneous software purchases and upgrades.

Q. Why do power operations O&M costs increase by $3.9 million between 2007 and 2009?

A. There are several reasons why power operations costs increase. First, much of the increase of $1.6 million in power supply and electricity dispatch costs is to meet the requirements of a more complex and regulated environment. This includes the addition of four new FTEs along with the services of at least one wind output forecasting service. These new positions represent one trainer of real-time operators on current and changing compliance regulations, two real-time operators to cover real-time shifts for operators out for training, PTO and other absences, and one FTE primarily responsible for integration of renewable resources into our supply portfolio.

Second, we expect work associated with maintaining existing power supply operations and technology systems to increase by approximately $0.5 million. The power operations IT allocation also increases by $0.5 million. IT allocations are discussed in greater detail in PGE Exhibit 500.

Third, at this time we include an additional $0.8 million to meet the requirements of FERC Orders 890 and 890-A. As a result of these FERC orders, we will no longer be able to buy or sell energy as a system sale or purchase but will instead be required to tag each transaction as "sourced" from a specific generation resource. Tagging sales and purchases from specific resources will add considerably to our employees' work load. PGE has joined several other Northwest utilities requesting a variation in the pro forma Open Access Transmission Tariff (OATT) that will define a system as a group of generators and therefore minimize tagging administration. Unless our filing is accepted by FERC, PGE will need to add seven and a half new FTEs to perform this additional tagging work resulting from FERC Orders 890 and 890-A on a 24-hour, 365-day basis.

An additional regulatory requirement that has impacted our operating costs is the requirement by WECC to identify which party (the buyer or seller) is responsible for providing reserves. In the past, the seller was always assumed to have the obligation to provide reserves. Because of this change, PGE is unable to rely on the Intercontinental Exchange (ICE), an electronic platform for executing electricity purchase and sell transactions because this system does not provide the required information and, therefore, PGE must transfer this activity to the broker markets that have the ability to meet this requirement. The cost increase is related to the higher transaction fees charged by the brokers.

Q. What is PGE's overall strategy for operating, maintaining, and upgrading its generating plants?

A. We operate, maintain, and upgrade our plants to achieve high reliability and availability. Ensuring that these resources are available to meet customer loads reduces power costs because the variable costs of most of our plants (mostly fuel) are generally less than the market price of electricity. In the case of PGE's coal plants, the variable costs are substantially less then the market price of electricity in most hours of a typical year.

Q. Does PGE have any initiatives aimed at maintaining high plant reliability?

A. Yes. We have recently started our Generation Excellence Initiative.

Q. What is PGE's Generation Excellence Initiative?

A. This high level initiative focuses on the changing needs of PGE's plants and maintaining maximum plant availability. Its cornerstones are improvement in four areas: improved safety, employee performance, plant reliability, and process improvements. As part of this initiative, in 2008, we will install a new high-fidelity simulator at the Boardman plant. This simulator will provide training on operating and responding appropriately to a wide range of possible Boardman-specific events, thereby maintaining the skills of the operating crews and minimizing the probability of outages due to operator error. Another example of this initiative is the creation of the Reliability Centered Maintenance (RCM) group. The RCM group, composed of three existing employees, conducts root cause analyses of problems that affect plant reliability and implements corrective action plans. Additionally, engineering will be performing Failure Mode and Effects Analyses (FMEA) to ensure design and operating risks are identified and addressed in a structured manner. Finally, we are developing a standardized maintenance program at our thermal and hydro plants, which will improve work and inventory management systems.

B. FTE Changes

Q. Please summarize PGE's plant and power operations related FTE changes from the 2007 forecast to the 2009 test year.

A. Table 2 below provides the plant and power operations related FTE changes from 2007 to 2009.

Table 2
Summary Plant-Related FTE Statistics

	2007 Forecast	**2008 Budget**	**2009 Test Year**
Hydro FTEs	74	76	69
Coal FTEs	74	77	81
Gas FTEs	76	88	88
Wind FTEs	0	5	5
General Plant FTEs	82	94	103
Power Operations FTEs	87	79	88
Totals	**393**	**418**	**434**

Q. Please discuss significant FTE changes listed in Table 2 above.

A. Hydro FTEs decrease in 2009, primarily because Bull Run will not be operating. Wind FTEs begin only in 2008 with Phase 1 of Biglow Canyon.

The increase in coal FTEs from 2007 to 2009 is due to the addition of seven FTEs at Boardman. We are adding an operator trainee and an assistant control operator, related to a new simulator at Boardman and other operation control room training. For succession planning and the ability to maintain full shifts during training, we will add two engineers, one planner, one plant serviceman for maintenance, and one administrative clerk.

Port Westward coming on-line in early June 2007 accounts for the increase in gas FTEs from 2007 to 2009. The 2007 Port Westward forecast figure is approximately 10 for the half year, whereas the 2009 test year figure is approximately 19 for the full year.

General plant FTEs increase in 2008 largely because of two new groups - for generation planning and for hydro and wind operational support. The generation project planning group is budgeted at four FTEs and will evaluate emission control alternatives for Boardman and other large potential projects. These FTEs had been working in our resource development group, which has now largely disbanded, as discussed below. The hydro and wind operation support group is budgeted at six FTEs and includes safety and training coordinators. This group will also support relicensing-related activities. In addition, we plan to hire a metallurgist and a civil engineer. The 2009 general plant increase is mostly for six FTEs in power supply engineering services. These include a non-destructive engineering examiner, a mechanical engineer, an electrical engineer, and three project managers – for Boardman emission controls and Phases 2 and 3 of Biglow Canyon. Three other FTEs will be assigned to multiple tasks, including hydro relicensing, distributed standby resources, net metering, and a solar initiative.

Power operations FTEs decrease substantially in 2008 because of a decrease of 13 FTEs in resource development and an increase of four FTEs in real-time operations and reliability services. With Port Westward and all other resources acquired through PGE's 2003 Request for Proposals now on-line, our resource development needs are now lower. Four of these positions essentially transferred to generation planning, as discussed above. Power operations FTEs increase in 2009 because of an additional seven and a half required FTEs for compliance with FERC Orders 890 and 890-A, which is discussed in more detail in Section II-A above.

C. Capital Additions

Q. Please summarize plant and power operations-related capital additions that close to plant from 2007 to the 2009 test year.

A. Table 3 below summarizes these capital additions that close to plant and hence, become part of rate base, from 2007 to 2009. Additional information regarding the timing of the closings is included in the work papers for PGE Exhibit 200.

Table 3
Capital Additions Closing to Plant ($million)

	2007 Forecast	2008 Budget	2009 Test Year
Coal	$13	$6	$36
Gas	260	5	1
Hydro	39	2	9
Hydro Relicensing		5	146
Wind	242		
DSG	1	1	1
Total	**$554**	**$19**	**$193**

Q. Please explain the major closings in Table 3.

A. The major closings are:

- In 2007, gas facilities closed to plant a total of about $260 million, $257 million of which was Port Westward.
- In 2007, $242 million was for Phase 1 of the Biglow Canyon wind farm.
- In 2007, hydro facilities closed to plant about $39 million. This includes $22 million for the River Mill fish ladder and the Willamette Falls control flow structure at the Sullivan plant.
- In 2007, $13 million at Boardman and Colstrip closed to plant. This includes NO_x controls, replacement of a cooling tower, and reliability maintenance at Colstrip.

- In 2009, $36 million is expected to close to plant at our coal plants. At Boardman, $15 million is to rewind the stator and convert the cooling system and $12 million is for the purchase and storage of a generator spare rotor.
- In 2009, $146 million for hydro relicensing is expected to close to plant. We expect the $81 million Round Butte Selective Water Withdrawal Tower project to close to plant in March 2009 and $65 million for the Westside hydro relicensing project to close to plant in December 2009. The relicensing costs include professional services (e.g., outside consultants, engineering, research, financial, legal, accounting, and purchasing), AFUDC, direct labor, and tax and license fees associated with our Oak Grove and North Fork hydro facilities.

Q. How will the Selective Water Withdrawal Tower (Tower) work?

A. This new intake tower will have two functions. First, by allowing water to be withdrawn from the Round Butte reservoir at a variety of depths, the Tower will create more distinct currents through the reservoir. These currents will guide downstream migrating juvenile salmonids to new fish collection facilities. Second, the Tower will improve water quality, both in the project reservoirs and downstream of the project by directing the warmer surface water from the Crooked River to Round Butte's turbine and the colder water to the downstream outflow. Downstream water temperatures will then be reduced, the lower Deschutes will return to pre-dam conditions, and increase salmon and trout populations should increase.

Q. How do these capital additions closing to plant impact the 2009 test year rate base?

A. All 2007 and 2008 additions are fully included in the 2009 rate base, net of a small amount of depreciation. The Tower will close in March of the test year; therefore, we will effectively include it in 9.5 of the 12 months and its average rate base impact will be about $64 million.[2] The Boardman rewind and water supply projects will be in rate base for 5.5 months of the test year, increasing average rate base by approximately $7 million. The Westside hydro relicensing costs and the spare rotor and warehouse at Boardman will have very little impact on the test year rate base, as they close at the end of 2009.

[2] This is consistent with calculation of the test year rate base as the "average of averages." The March average, 40.5, which is part of the annual average, is calculated as [(0 + 81) / 2], or the average of the end of February and end of March balances.

IV. Hydro Relicensing Update and Related Revenue Requirement

Q. What is the status of the relicensing process for Pelton Round Butte, Willamette Falls and Clackamas projects?

A. On June 21, 2005, PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) jointly received a new 50-year FERC license for the Pelton Round Butte Project, which consists of three developments located on the Deschutes River. PGE has majority ownership shares in two of these developments, Pelton and Round Butte. The third facility, the re-regulation dam (and associated powerhouse), is completely owned and operated by the Tribes.

On December 8, 2005, PGE received a new 30-year FERC license for the Willamette Falls Project, which includes our Sullivan facility, located on the Willamette River.

PGE is currently in the process of obtaining a new long-term license for the Clackamas River Hydroelectric Project, which is also under FERC jurisdiction. This project consists of four plants – Oak Grove, North Fork, Faraday, and River Mill – all owned by PGE.

Q. What is PGE's current focus in the Clackamas Project relicensing process?

A. We are currently focused on water quality issues. We expect to file a new 401 Water Quality Application with the Oregon Department of Environmental Quality in the second quarter of this year.

Q. What benefits does PGE's decision to pursue new long-term licenses for the Pelton Round Butte, Willamette Falls, and Clackamas Projects provide for customers?

A. Relicensing provides customers with a long-term source of power at low, stable prices. Section III of PGE Exhibit 300 in Docket UE 180 (PGE Exhibit 403 in this filing) provides an extensive discussion of how relicensing compares very favorably to other resource alternatives, from both expected cost and risk perspectives.

Q. Do the license conditions significantly decrease expected output of the projects?

A. No. Any power output decreases resulting from license conditions will be very minor.

Q. What projects required by the new licenses will PGE have completed by the 2009 test year?

A. At Willamette Falls, we completed construction of the North Fish Bypass in 2006 and the Flow Control Structure in 2007. We plan to remove the Blue Heron Powerhouse in 2008. At Pelton Round Butte, we began construction of the Selective Water Withdrawal Tower in 2007. We expect to finish this project in March 2009.

Q. Do the hydro O&M expenses you discussed in Section III-A of your testimony include costs associated with protection, mitigation, and enhancement measures required by the new long-term licenses?

A. Yes. For example, the hydro O&M figures in Table 1 above include costs required for road maintenance and recreation site improvement at Pelton Round Butte and fish ladder maintenance at Willamette Falls.

Q. What licensing structure supports operation of the Clackamas Project prior to issuance of a new long-term license?

A. The four facilities included in the Clackamas Project were previously covered by two separate long-term licenses for the Oak Grove and North Fork Projects. These licenses expired on August 31, 2006. An "annual license" currently allows the four plants to continue operation under the terms of the Oak Grove and North Fork Project licenses while FERC considers the new long-term Clackamas Project application. If additional "annual licenses" are required prior to the new long-term Clackamas Project license, they will be issued automatically.

Q. At the time PGE decided to pursue new long-term hydro licenses, OPUC Order No. 89-507 governed the integrated resource planning process. This order directed utilities to consider both cost and risk in their resource decisions. Do PGE's hydro relicensing decisions meet the Order No. 89-507 criteria?

A. Yes. With respect to expected costs, PGE's UE 180 testimony, PGE Exhibit 300, Section III explained that the estimated costs of relicensing hydro resources compared very favorably to the costs of other alternatives at the time PGE decided to seek new long-term licenses (included as PGE Exhibit 403). With respect to risk, relicensing compares very favorably with other alternatives. The costs incurred to meet the license conditions will almost all be fixed, whereas the costs of other resource alternatives will be subject to much more variation over time – changing market electric prices, changing fuel prices, possible changes related to CO_2 standards, etc.

V. Qualifications

Q. Mr. Quennoz, please describe your qualifications.

A. I hold a Bachelor of Science degree in Applied Science from the U.S. Naval Academy and hold Masters Degrees in Operations Analysis from the University of Arkansas, Mechanical Engineering from the University of Connecticut, Nuclear Engineering from North Carolina State University, and an MBA from the University of Toledo. Prior to working for PGE, I held positions as Plant Superintendent at the Davis-Besse Nuclear Station for Toledo Edison and General Manager at the Arkansas Nuclear One Station for Arkansas Power and Light. I also coordinated restart of the Turkey Point Nuclear Station for Florida power and Light. I joined PGE in 1991 and served as Trojan Plant General Manager and Site Executive. I assumed responsibilities for thermal operations in 1994 and hydro operations in 2000. I was appointed Vice president, Nuclear and Thermal Operations in 1998, and Vice president Generation in 2000. I've held my current position of Vice President, Supply since August 2004. My responsibilities include overseeing all aspects of PGE's power supply, as well as the decommissioning of the Trojan nuclear plant. I am a registered Professional Engineer (P.E.) in the State of Ohio.

Q. Mr. Lobdell, please describe your qualifications.

A. I received a Bachelor of Science degree from the University of Oregon in 1984. Since joining PGE in 1984 I have held a variety of positions at PGE and its affiliates including Vice President, Risk Management, Reporting, and Control, Vice President of Portland General Distribution Company, Vice President of Portland General Holdings II, Vice President of FirstPoint Utility Solutions, Manager of Financial Risk Management and Pricing at PGE, Treasurer of Tule Hub Services Company, Manger of Commercial Group

Accounting for Portland General Holding, Project Manager for Columbia Willamette Development Company, and Supervisor of Accounting Operations for Portland General Corporation. I entered my current position of PGE Vice President of Power Operations in September 2002.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
401	Generating Resource Summary
402	IR and PTP Transmission Resource Summary
403	Section III of PGE Exhibit 300 in Docket UE 180

PGE's 2009 Supply Resources

Resources	Capacity (1) (MW)	Energy (2) (MWa)
Plants		
Boardman	380	284
Colstrip	296	250
Port Westward	417	232
Coyote I	245	156
Beaver	521	46
Beaver 8	24	0
Round Butte	225	76
Pelton	73	34
Oak Grove	44	27
North Fork	58	27
Faraday	46	26
River Mill	25	14
Sullivan	16	14
Plant Total	2,370	1,186
Contracts		
Wells	171	85
Rocky Reach	152	84
Grant County Settlement	292	164
Tribes	161	65
Canadian Entitlement	(29)	(16)
Portland Hydro	36	10
Klondike II (3)	11	27
Biglow I (4)	19	48
Vansycle Ridge	4	8
TransAlta Power Purchase	100	92
Morgan Stanley Power Purchase	25	25
Morgan Stanley Tolling	25	11
Spokane Energy Capacity	150	0
PPM Winter Super-Peak Option	100	0
PPM Exercise Limited Option	300	0
EWEB Capacity	10	0
Covanta PURPA Contract	10	10
Glendale Sale	(20)	(11)
Glendale Exchange (5)	30	0
Chelan Exchange (6)	0	0
Wells Settlement Agreement	17	22
Contract Total	1,564	624
All Resource Total	3,934	1,810

(1) Capacity measures are for January. Note that the capacities of gas-fired plants are inversely related to temperature. Figures for Boardman, Colstrip, Pelton, and Round Butte are PGE shares.

(2) Some resources, particularly thermal plants, are subject to economic dispatch; hence annual output varies from year to year. Figures in the table for Boardman, Colstrip, Port Westward, Coyote I, and Beaver are based on forecasted 2009 economic dispatch.

(3) Klondike II has 75 MW of nameplate capacity, but this is not the same as reliable capacity. We set capacity equal 15% of nameplate capacity in our 2006 IRP.

(4) Biglow I has 125 MW of nameplate capacity.

(5) The City of Glendale Exchange provides 11 MWa of energy during November-February winter seasons in exchange for similar obligations from PGE to Glendale during June-September summer seasons.

(6) The Chelan Exchange provides 50 MW of summer capacity.

PGE's Contract Summary

IR Contract Summary

Point of Receipt	Max Capacity (MW)
Beaver	531
Coyote Springs	250
Colstrip	270
Boardman	379
Wells	169
Priest Rapids	131
Rocky Reach	177
Wanapum	161
Spokane Energy	150
Total IR	2218

Note: Points of delivery are on the PGE System or the head of the interie.

PTP Contract Summary

Point of Receipt	Max Capacity (MW)	Term
John Day	300	5 yrs ending 9/2010
Big Eddy	100	5 yrs ending 9/2010
Mid-Columbia (Rocky Reach)	600	5 yrs ending 6/2010
Federal System (Vansycle Ridge)	25	15 yrs ending 11/2016
Federal System (Biglow Canyon)	150	5 yrs ending 9/2010
Total PTP	1175	

Note: Points of delivery are on the PGE System or the head of the interie.

III. Hydro Relicensing

A. Introduction

Q. Why are you addressing hydro relicensing in this filing?

A. The 2007 test year is the first to include costs related to this effort, which PGE began in 1995. This test year includes some O&M associated with new licensing requirements, as well as some capital expenditures, including those associated with obtaining new licenses for Pelton, Round Butte, and Sullivan. Our new licenses will require capital expenditures of approximately $370 million. Although we have already incurred some of these costs, most are for activities that will occur between now and 2020. O&M expenses will also increase. Using a collaborative process, however, we preserved the cost-effective status of these resources and avoided any significant decrease in their performance. The latter is important because, at zero variable fuel cost, production capability is the key to the value of these resources.

Q. How is this section organized?

A. Part B summarizes the hydro projects PGE decided to relicense and the related costs, test year revenue requirement, and measures of cost effectiveness. Part C describes the approach to relicensing that PGE took under the Federal Energy Regulatory Commission's (FERC) general licensing procedures.

B. Relicensing and Related Revenue Requirement

Q. Which hydro projects has PGE recently relicensed or is PGE in the process of relicensing?

A. On June 21, 2005, PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes) jointly received a new 50-year FERC license for the Pelton Round Butte Project, which consists of three developments located on the Deschutes River. PGE has majority ownership shares in two of these developments, Pelton and Round Butte. The third facility, the re-regulation dam (and associated powerhouse), is completely owned and operated by the Tribes. On December 8, 2005, PGE received a new 30-year FERC license for the Willamette Falls Project, which includes our Sullivan facility, located on the Willamette River. PGE is currently in the process of obtaining a new long-term license for the Clackamas River Hydroelectric Project, which is also under FERC jurisdiction. This Project consists of four developments – Oak Grove, North Fork, Faraday, and River Mill – all owned by PGE.

Q. Overall, what relicensing costs has PGE incurred and does PGE expect to incur in the future?

A. These costs fall into three primary categories: capital additions, relicensing process costs, and O&M. First, we expect to invest approximately $301 million for fish ladders, a water intake structure, and other capital additions. Second, we will capitalize approximately $70 million in relicensing process and studies costs. Third, protection, mitigation, and enhancement (PME) measures required by the licenses will increase O&M costs for the projects. The new licenses and related settlements require several measures. For Pelton Round Butte, these include road maintenance and improvements to recreation sites. For

Willamette Falls, PME measures include the responsibility for fish ladder maintenance. Our Clackamas Project will likely require similar PME measures. We project total relicensing-related O&M costs to be approximately $3 million in 2007 increasing to approximately $7 million in 2009, then decreasing to approximately $3 million in 2015, and generally increasing at 2.5% per year thereafter.

Q. Have you prepared a summary table of costs – both actually incurred and projected – by year and by project?

A. Yes. PGE Exhibit 303 provides this information. Pages 1 and 2 of that Exhibit cover capital and O&M costs respectively.

Q. How do these costs affect the test year revenue requirement?

A. The test year net rate base includes approximately $41.7 million related to relicensing. Given the pre-tax cost of capital of slightly less than 13%, the return requirement is approximately $5.4 million. The test year revenue requirement also includes relicensing-related depreciation and O&M expenses of approximately $1.0 million and $2.9 million respectively, resulting in a total hydro relicensing-related revenue requirement of approximately $9.3 million.

Q. Has PGE decided not to relicense any of its hydro projects?

A. Yes. We decided not to seek a new long-term license for Bull Run, our 22 MW hydro facility located on the Bull Run River, just upstream from its confluence with the Sandy River. We determined that the costs associated with measures necessary to obtain a new long-term license would likely exceed the value of the associated power output.

Q. Have you calculated "per MWh" costs for power to be produced by the relicensed plants?

A. Yes. Our calculations reflect the amounts and timing of all costs – both relicensing and other – related to running the hydro facilities covered by the Pelton Round Butte, Clackamas River, and Willamette Falls Projects through the end of the new license terms. We know that the new Pelton Round Butte and Willamette Falls licenses end in 2055 and 2035 respectively. We assume that the new Clackamas River license will run through 2052.

Using "average water," as explained in PGE Exhibit 400, and on a real levelized 2006 dollar basis, these costs are:

- Pelton $21.83/MWh
- Round Butte $22.66
- Clackamas Project $41.90
- Sullivan $45.26

These are substantially lower than comparable levelized market prices of more than $53/MWh.

Q. What net present values result from your calculations?

A. We expect relicensing to provide customers with the following net present value benefits ($2006 Million):

- Pelton $165
- Round Butte $375
- Clackamas Project $143
- Sullivan $ 14
- Total $697

Q. How does the cost of relicensing hydro resources compare to the cost of other resource alternatives?

A. It compares very favorably. The average cost of the resources that are part of PGE's most recent Commission-acknowledged Final Action Plan is more than $40/MWh, even assuming the gas forward curves used to evaluate the RFP bids and the Port Westward alternative. This average would be substantially greater using current forward curves. We base the net present value calculations on an expected long-term 2006 real levelized market power price of more than $53/MWh.

C. Hydro Relicensing Process

Q. Please describe the new long-term licenses that PGE has obtained or is pursuing.

A. FERC issues licenses for hydro facilities with terms ranging from 30 to 50 years.

Our two Deschutes River developments, Pelton and Round Butte, operated under one long-term license for the Pelton Round Butte Project, which expired at the end of 2001. After expiration of the long-term license, the project operated under "annual licenses." On June 21, 2005, FERC issued a new long-term (50-year) license.

For FERC licensing purposes, PGE's Sullivan facility was designated as the Willamette Falls Project. This project, whose long-term license expired on December 31, 2004, was operating under an "annual license" until December 8, 2005, when FERC issued a new long term (30-year) license.

With respect to the Clackamas River, we plan to renew the long-term license for our Oak Grove, North Fork, Faraday, and River Mill developments. These facilities were originally covered by two licenses, one for the Oak Grove Project, the other for the North Fork Project which includes our North Fork, Faraday, and River Mill plants. The two licenses were recently combined and designated as the Clackamas River Project. The current license expires on August 31, 2006, and we have requested a 45-year license. It is impossible to predict when FERC will act on our pending Clackamas application.

Q. What is the relicensing process like in general?

A. The FERC relicensing process is complex and time consuming (usually a minimum of five years). In making relicensing decisions, FERC must consider fish and wildlife, recreational, land use, cultural, and aesthetics issues equally with energy production. Certain federal and state resource agencies, known as "mandatory conditioning agencies," have specific authority to include requirements in FERC issued licenses. These requirements are often expensive, and can limit hydro plants' operational flexibility. Examples are mandatory measures for fish passage and minimum in-stream flows. Often there is insufficient scientific knowledge to objectively determine the environmental effectiveness of some proposed mandatory conditions. Moreover, the FERC relicensing process can become extremely contentious and political. Given this environment, PGE used a collaborative approach to reduce costs and uncertainties wherever possible.

Q. Please describe the relicensing process for the Pelton Round Butte Project.

A. PGE began the relicensing process for the Pelton Round Butte Project in 1995. Following several years of relicensing discussion, PGE and the Tribes filed their Final Joint Application Amendment in June 2001. On August 11, 2002, FERC issued the Ready for Environmental Analysis Notice. This is essentially a determination that FERC has sufficient information to analyze the environmental impacts of relicensing the project. To resolve remaining issues, PGE and the Tribes began a multiparty, facilitated negotiation process in January 2003. Negotiations concerning fish passage, minimum flows below the plants, and associated operational issues, were complex and time consuming. In addition, discussions of the plants' water rights related to future municipal and other water use demands involved many parties. Reaching consensus required a lot of time.

On August 29, 2003, FERC issued its Draft Environmental Impact Statement. In December 2003, PGE and the Tribes filed a description of the Proposed Preferred Alternative with FERC. FERC issued its Final Environmental Impact Statement in June 2004. Parties signed the Settlement Agreement on July 13, 2004, and PGE filed the agreement with FERC on July 30, 2004. FERC issued a new long term license for the project on June 21, 2005.

Q. What were the advantages of PGE's decision to use a multi-party, facilitated negotiation process to relicense the Pelton Round Butte Project?

A. Thirteen agencies claimed some form of mandatory conditioning authority in the relicensing of the Pelton Round Butte Project. A collaborative settlement process provided the best opportunity to reconcile potentially inconsistent demands from these agencies and to maintain the economic benefits of the project for customers. The negotiated settlement involving all parties also greatly reduced the risk of litigation. Litigation over licenses increases costs to customers and raises uncertainty. Moreover, PGE believes that facilitated settlement processes involving all parties create the best opportunity for creative problem solving. We also expect the negotiated settlement to reduce controversy during the implementation of license terms, resulting in more efficient and lower cost implementation of programs.

Q. What must PGE do to meet the conditions of the Settlement Agreement that was part of the Pelton Round Butte Project relicensing process?

A. The Settlement Agreement and the new license, which largely adopts the terms of the agreement, have numerous requirements. The license terms address both project operations and measures to address all resource categories impacted by the project. These categories include wildlife and botanical resources, fisheries, water quality, recreation, culture, road maintenance, and other land uses.

Of particular significance, the new license contains an aggressive fish passage plan, which aims to reintroduce salmon and steelhead above the Round Butte Dam through construction of a new intake tower at the dam.

Q. How will the new intake tower at Round Butte work?

A. The new intake tower, also designated as the Selective Water Withdrawal Tower (Tower), will have two functions. First, by allowing water to be withdrawn from the Round Butte reservoir at a variety of depths, the Tower will create more distinct currents through the reservoir. These currents will guide downstream migrating juvenile salmonids to new fish collection facilities. Second, the Tower will improve water quality, both in the project reservoirs and downstream of the project.

Q. Will the changes made to meet the conditions of the Settlement Agreement alter the output and availability characteristics of Pelton and Round Butte?

A. No. Although the project will operate under a clearer and somewhat more restrictive set of target flows and reservoir levels, the key components of project operations, average energy, and peaking capability, remain intact.

Q. Will the changes made to meet the conditions of the Settlement Agreement change the O&M costs of Pelton and Round Butte?

A. Yes. Many of the requirements of the Settlement Agreement will increase O&M costs. In particular, PGE will pay various entities for road maintenance and law enforcement costs. Also, we will increase the biological staff dedicated to the project and to license implementation. Finally, annual charges paid to the State of Oregon and FERC will increase. Pelton and Round Butte PME-related O&M costs are approximately $2.3 million for the 2007 test year.

Q. Are all hydro relicensing costs directly related to license articles?

A. No. Although it is in all parties' interest to agree on the PME measures that FERC will enforce, there are instances in which the relatively narrow nature of FERC's jurisdiction over licensees does not cover all measures requested by the different parties. In these instances, PGE's negotiating team calculates the cost of these measures and compares those costs to the costs that PGE could incur if we did not achieve settlement.

Q. What are the primary settlement-related costs for Pelton Round Butte that do not directly relate to license articles?

A. In its order issuing a new license for Pelton Round Butte, FERC omitted two elements to which the settling parties had agreed:

1. Support for improvements of Forest Service facilities at Haystack Reservoir. This portion of the agreement requires PGE to pay $10,000 to the Forest Service in the fifth year of the new license. Additional payments of $15,000 each follow in years 20 and 40 of the new license.
2. Improvements to recreation sites on the lower Deschutes. This group of measures requires PGE to support a variety of upgrades to heavily used camp sites along the

Deschutes River below the project. The agreed upon level of support is $87,000 in the fifth year of the license and an additional $49,500 in the seventh year.

Q. What risks did PGE avoid by reaching settlement with all parties?

A. Had we not reached an agreement with all parties, federal and state agencies would have been free, within the limits of their statutory authorities, to mandate mitigation measures that FERC would have been obliged to include in the license. At that point, PGE's only practical recourse would have been to appeal issuance of the license to the federal Court of Appeals. It was PGE's judgment that the outcome of such litigation would have been a license which was, on its face, more expensive for customers than the settlement alternative, and could have involved significant litigation costs as well.

Q. Please describe the process PGE used to relicense the Willamette Falls Project.

A. In relicensing the Willamette Falls Project, we used a variant of FERC's Alternative Licensing Process, under which PGE prepares the environmental assessment on FERC's behalf. Participants in the relicensing process worked in a collaborative fashion, tackling issues incrementally in small technical work groups. This process was successful and resulted in the filing of a Settlement Agreement with FERC in January 2004. All parties have signed this agreement.

The most prominent issue at Willamette Falls was downstream passage of salmonids. Concerns also arose about safe passage of lamprey, a species of cultural significance to the Grand Ronde, Siletz, and Warm Springs Tribes. Petitions were submitted for listing lamprey under the Endangered Species Act. There were also issues regarding traditional tribal uses in the area of the falls. Finally, some parties requested increased public access to the falls through the project and adjacent paper mills. PGE could not meet these requests because of project and paper mill safety concerns and FERC's recent increased emphasis on project security.

PGE filed the Final License Application in December 2002. FERC issued its Draft Environmental Assessment in January 2004, the same month in which PGE filed the Settlement Agreement with FERC. FERC issued its Final Environmental Assessment in October 2004 and a new 30-year license in December 2005.

Q. What must PGE do to meet the conditions of the Willamette Falls relicensing-related Settlement Agreement?

A. PGE must operate the project in accordance with a more restrictive set of license articles. In addition, PGE will upgrade the turbines at Sullivan to improve the units' operating efficiencies and to make them more "fish-friendly." The Settlement Agreement also requires the decommissioning of a small powerhouse previously owned by Blue Heron Paper Company. Finally, the Agreement requires a phased program of improvements to the fish passage facilities at Sullivan and at Willamette Falls themselves.

Q. Will the changes made to meet the conditions of the Settlement Agreement alter Sullivan's output and availability characteristics?

A. No. The Settlement Agreement conditions will leave availability characteristics virtually unchanged.

Q. Will the changes made to meet the conditions of the Settlement Agreement change Sullivan's O&M costs?

A. Yes. The O&M costs at Sullivan will increase, largely for PGE responsibility for maintenance of the Oregon Department of Fish and Wildlife fish ladder located at the site. Sullivan PME-related O&M costs are approximately $200,000 for the 2007 test year.

Q. What process has PGE used to relicense the Clackamas River Hydroelectric Project?

A. For the Clackamas River Project we are using a variant of FERC's Alternative Licensing Process. Under this process, FERC's National Environmental Policy Act (NEPA) contractor, the firm that will eventually write the Environmental Impact Statement for FERC, participates in the process from the beginning, working with the applicant and relevant agencies. Relicensing participants work in a collaborative fashion, tackling issues incrementally in small technical work groups.

Much of the Oak Grove portion of the project is on Forest Service lands, which gives the Forest Service broad authority to mandate license conditions. Flow below the Harriet Lake diversion dam is a significant issue. Proximity to the Portland metropolitan area makes recreational use of the Clackamas Basin a major factor. Finally, most portions of the project have some form of up- and down-stream fish passage. The efficiency and appropriateness of the fish passage system is a major concern.

Relicensing participants completed scoping, the first phase of the collaborative process, and PGE issued a revised Scoping Document in April 2003. Concurrent with relicensing, PGE asked for a license amendment as part of its Endangered Species Act (ESA) compliance strategy. In June 2003, FERC granted this amendment, which included several fishery conservation measures and authorized new turbine runners at North Fork and Faraday #6. PGE issued the initial draft of its Preliminary Draft Environmental Impact Statement at the end of September 2003 and filed its Final License Application and associated Preliminary Draft Environmental Impact Statement in August 2004. With the completion of the Final License Application, PGE convened a settlement group, whose goal was to resolve the licensing issues via a collaborative settlement.

Q. Was the settlement group successful?

A. Yes. The group reached consensus on the outstanding issues. This resulted in an Agreement in Principle, which was filed with FERC on June 30, 2005.

Q. What must PGE do to meet the conditions of the Agreement in Principle?

A. As with the Pelton Round Butte Project, the Agreement for relicensing the Clackamas River Project contains significant measures to improve the survival of salmon and steelhead passing through the project. Of greatest significance, the agreement contains minimum flows in the Oak Grove Fork of the Clackamas River below Harriet Dam and requires new fish passage facilities to be constructed at PGE's North Fork and River Mill facilities. The agreement also contains measures to improve recreation in the project area, and to protect wildlife habitat and species, cultural and historical resources, and water quality.

Q. Will the changes made to meet the conditions of the Agreement in Principle alter the output and availability characteristics of PGE's Clackamas River hydro facilities?

A. The availability characteristics of the four facilities included in the Clackamas River Hydroelectric Project will remain largely unchanged. The combined energy output of these three plants will fall by approximately seven MWa because of increased minimum flow requirements at Oak Grove and Faraday, and head loss at North Fork.

Q. Will the changes made to meet the conditions of the Agreement in Principle change the O&M costs of PGE's Clackamas River facilities?

A. Yes. Staffing requirements to fulfill license obligations, increased operational requirements for campgrounds, and payments for road maintenance and law enforcement will increase O&M. Clackamas PME-related O&M costs are approximately $400,000 for the 2007 test year.

Q. Why did PGE decide to use a collaborative variant of FERC's Alternative Licensing Process for its Clackamas River and Willamette Falls Projects?

A. This choice provided the best chance of creating firm information bases and preliminary agreements, which could then serve as the foundations for comprehensive settlements. The collaborative process resulted in negotiated settlements, which will likely reduce both the controversy during license term implementation and the possibility of litigation. This reduction of conflict is likely to reduce costs and uncertainties for customers.

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PIRO - TOOMAN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Corporate Support

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

James J. Piro
Alex Tooman

February 27, 2008

Table of Contents

I. Introduction

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

A. My name is James J. Piro. I am the Executive Vice President, Finance, Chief Financial Officer, and Treasurer at PGE. My qualifications appear in PGE Exhibit 100, Section VIII.

My name is Alex Tooman. I am a Project Manager for Regulatory Affairs at PGE. My qualifications appear in PGE Exhibit 200, Section IX.

Q. What is the purpose of your testimony?

A. We explain PGE's request for $120.5 million in administrative and general (A&G) costs in 2009 and compare it to the 2007 forecast (with nine months of actual activity and three months of budgeted costs) of $107.2 million.

Q. What functions are classified as A&G and what are the costs of those functions?

A. We classify as A&G those functions, such as human resources, accounting and finance, insurance, contract services and purchasing, corporate security, regulatory affairs, legal services, and information technology (IT), that support PGE's direct operations. We also include other costs such as employee benefits and incentives, support services, and regulatory fees that fall within the FERC definition of A&G. PGE Exhibit 501 provides a list of A&G functions plus a summary of costs and full time equivalent (FTE) employees for 2007 through 2009. Table 1 below summarizes the major A&G costs by functional area.

Q. Why are these costs necessary?

A. The A&G functions are the "back office" of PGE. While they do not generally interact directly with customers, they provide essential services that allow any company to operate. They ensure that the "numbers" are right through the accounting and auditing functions. They acquire sufficient capital and materials to meet PGE's capital and operating requirements. They supply appropriate facilities and technology. As mentioned above, PGE's staffing and employee benefits are part of A&G, as are legal representation and interaction with our communities, regulators, and the media.

Table 1
A&G Costs by Major Functional Area ($Million)

Major Functional Areas	2007 Forecast (9+3)[1]	2008 Budget	2009 Forecast
Facilities/General Plant Maintenance	10.7	10.9	11.1
Accounting/Finance	8.2	9.0	9.2
HR/Employee Support/Ethics and Compliance	4.4	5.0	6.5
Insurance, Injuries and Damages, etc.	9.6	10.9	11.2
Legal	5.9	6.3	6.0
Federal and State Regulatory Affairs	2.3	2.6	2.8
Corporate Governance	2.8	3.2	3.4
Business Support Services	2.1	2.3	2.4
Environmental Programs	0.9	0.9	1.2
Corporate R&D	0.3	0.3	1.0
Contract Services/Purchasing	1.1	1.2	1.3
Security and Business Continuity	0.8	1.1	1.3
Corp Communications/Public Affairs	1.4	1.9	2.1
Load Research	0.1	0.2	0.2
Hydro Licensing	0.2	0.5	0.6
Governmental Affairs	0.9	0.9	1.1
Total for Major Functional Areas	**$ 51.9**	**$ 57.4**	**$ 61.5**
IT: Direct & Allocated	6.9	7.8	8.3
Other Service Providers to A&G	0.3	0.6	0.4
Benefits (net of capital allocs.)	29.5	28.9	32.3
PTO Loadings to A&G	3.8	4.0	4.2
Incentive Plans (net of capital allocs.)	18.0	14.0	14.6
Regulatory Fees	4.3	5.7	6.6
Other Membership Costs	1.1	1.5	1.5
Miscellaneous	-0.2	-4.4	-0.1
Total Other A&G Costs	**$ 63.8**	**$ 58.1**	**$ 67.8**
Capitalized A&G	-6.7	-6.7	-6.9
Duplicate Charge Offset	-1.8	-1.8	-1.8
Total A&G Offsets	**-8.5**	**-8.5**	**-8.7**
Total A&G	**$107.2**	**$107.0**	**$120.5**

Q. How do you measure success for the A&G functions?

A. Although operating metrics resulting from a direct tie to customers do not apply to A&G, measures we look at include:

[1] The 2007 forecast represents nine months of actual data and three months of remaining budget.

- Unqualified opinions from our independent auditors on our financial statements;
- Financing costs in line with similar rated companies;
- Wages and benefit costs consistent with the mid-point of the market;
- Meeting all regulatory, compliance, and tax reporting requirements; and,
- Reliability and availability of our IT systems.

Q. How have you performed?

A. In general, we believe we've performed very well. For example, PGE has always had an unqualified opinion from our external accounting auditors (i.e., a clean audit report). PGE also continues to maintain a strong capital structure and we have always maintained investment-grade ratings with Standard and Poor's and Moody's.

Q. Table 1 shows A&G expenses have increased by approximately $13.3 million from 2007 to 2009. What are the main reasons for this increase?

A. The primary reasons for the higher costs in 2009 are as follows:

- Increasing wages, incentives, and benefit costs (discussed in PGE Exhibit 800, Compensation);
- Higher insurance premiums;
- New projects for research and development;
- Increasing Oregon Public Utility Commission (OPUC) fees;
- Increasing membership costs for PGE's participation in the Western Electricity Coordinating Council (WECC);
- New activities and FTEs related to business continuity and emergency management;

- Payments to Sherman County for the Strategic Investment Program Agreement in lieu of property taxes; and,
- Higher levels of IT costs.

Q. How is your testimony organized?

A. In the next section, we discuss the major cost drivers in more detail, including additional information regarding total IT as it relates to all functional areas. In the final section, we describe additional A&G costs that are not included in the current revenue requirement but will be part of PGE's errata filing to this testimony. (Note: PGE has previously described each functional area in detail in its last general rate case, UE 180. Thus, we focus on only the major areas of cost increases from 2007 to 2009.)

II. Major Cost Increases by Driver

A. Wages, Incentives, and Benefits

Q. To what extent do you forecast costs for wages, incentives, and non-labor inflation to increase from 2007 to 2009?

A. PGE forecasts the increase from 2007 to 2009 to be approximately $1.2 million, based on the following:

- Wage escalation for both union and non-union employees, $4.1 million;
- Incentive costs, ($3.5 million); and
- Materials, supplies and other non-labor inflation, $600,000

Q. In addition to the previous costs, by how much are costs for benefits estimated to increase?

A. The increase for benefits from 2007 to 2009 is approximately $2.8 million and includes such items as health and dental plans, 401K plan, workers' compensation, and employee life and disability insurance.

Q. Why have these costs changed?

A. All of the wage, incentive, and benefits-related costs are discussed in detail in PGE Exhibit 800 (Compensation), which explains how these costs are necessary for PGE to remain competitive in a tight labor market for specialized and qualified applicants. The wage escalation represents the estimated amount that A&G labor costs will increase from 2007 to 2009 due to increases in wages and salaries. The incentive and benefit amounts represent the "net" changes within A&G only, as compared to the gross costs applicable to corporate PGE. Net A&G refers to the amount remaining in A&G after labor loadings apply certain amounts of these costs to capital projects and "below-the-line" activities. PGE Exhibit 800 explains the gross corporate forecast for these costs.

B. Insurance Premiums

Q. By how much are insurance costs expected to increase from 2007 to 2009?

A. PGE's insurance costs are expected to increase by approximately $1.3 million from 2007 to 2009. The primary driver of this increase is property insurance premiums.

Q. Why are property insurance premiums forecasted to increase?

A. Property insurance premiums are forecasted to increase by approximately $900,000 from 2007 to 2009. This increase, however, consists of three components. The first is for All-Risk property insurance, which is forecasted to increase approximately $550,000 between 2007 and 2009 due to increases in both PGE's insurable asset base and the rates charged by insurers. The All-Risk premium covers physical loss or damage to PGE property caused by perils such as fire, wind, lightning, flood, earthquake, and acts of terrorism. The increase in asset base occurs because: 1) coverage for the Port Westward plant began in July 2007, 2) coverage for Phase 1 of the Biglow Canyon Wind Farm will begin in 2008, and 3) replacement values of existing assets increase by approximately 4% per year based on trend factors from the Handy-Whitman Index of Public Utility Construction Costs.

Q. What are the other components of increasing property insurance costs?

A. The other components consist of a policy holder credit and builder's risk coverage premiums. In 2007, PGE received a policy holder credit of approximately $210,000 for its participation in a mutual insurance company that had favorable underwriting results in prior years. Consequently, while the variance from 2007 to 2009 includes this impact, it does not reflect an actual cost increase because these credits are very sporadic and relate to prior years' activity.[2] The builder's risk component represents a $130,000 increase over 2007 for property insurance related to construction in progress, and specifically, Biglow Canyon Phase 2 in 2009 versus Phase 1 in 2007.

Q. Do the builder's risk premiums represent one-time costs?

A. No. PGE plans to construct three phases of Biglow Canyon from 2007 through 2010. We also anticipate additional renewable projects that will be developed based on the outcome of our integrated resource planning and recurring rate cases to reflect the implementation of these projects. Therefore, this type of cost will be on-going beyond 2009.

Q. Since the builder's risk insurance costs are related to construction, can they be capitalized?

A. Yes, they should be capitalized. PGE will make an entry to this effect as part of the errata filing that we expect to make in late March or early April 2008.

Q. What other sources of increases exist for PGE's insurance premiums?

A. PGE expects liability insurance premiums to increase by approximately $300,000, which consists of $170,000 for Excess Liability insurance and $130,000 for Director and Officer Liability insurance. We also forecast a $50,000 increase associated with: 1) workers compensation premiums, and 2) declining refunds from the Industry Credit Rating Plan for nuclear insurance.

C. Research and Development

Q. What are your 2009 forecasted costs for corporate research and development (R&D) activities?

2 The previous credit occurred in 2001 for $110,000.

A. For 2009, we forecast approximately $1.0 million in R&D expenses, which represents an increase of about $700,000 from the 2007 forecast. We attribute this increase to time-sensitive issues that need to be addressed by both PGE and the State of Oregon. Examples of these issues include Oregon's Renewable Energy Standard (RES), global climate change, infrastructure changes, and the rapid pace of technology advances that can increase system reliability and efficiency in PGE operations. Projects currently planned for 2009 include:

- Distributed standby generation (DSG);
- Distributed energy storage;
- Highly efficient community-scale infrastructure;[3]
    - Solar ready infrastructure;
    - Geothermal heat pump infrastructure;
- Carbon/greenhouse gas (GHG) regulation;
    - Carbon capture;
    - Biotic carbon storage from flue gas;
    - Geologic carbon storage from flue gas;
    - Biotic carbon storage opportunities;
    - Addressing other green house gasses;
    - Tree planting for environmental benefits;
    - Renewable power or highly efficient Power generation at sub-utility or community scales;
- Other Areas of Anticipated Research;
    - Electric infrastructure access in support of Plug-in Hybrid Vehicles;

[3] Community scale represents small 1 – 10 MW projects that are placed relatively close to power grids and do not require load shaping and firming.

- Transmission planning in relation to renewable power generation locations;
- Energy work force development study to address the shortage of skilled electrical workers; and
- Visual mapping displays as Distribution control area management tools.

Q. How are these projects integral to PGE's success?

A. As customer loads grow, PGE must continue to add resources to its system. By increasing funds to PGE's R&D programs, we can actively participate, early in the decision making process, in demonstration projects and engage with other research groups that are also seeking to make knowledgeable and cost effective choices on environmentally benign, efficient, and reliable energy resources. For example, in PGE's 2007 Integrated Resource Plan (IRP), there is explicit discussion regarding the need to encourage and explore a variety of smaller scale renewable (e.g., solar, wind, and biomass) and highly efficient power technologies. This discussion is in the context of partnerships with other regional utilities and the Energy Trust of Oregon.

In addition, PGE can use R&D funds to improve the operation and maintenance of its generation and distribution systems and participate in opportunities to review and apply proposed improvements to its system through demonstration projects. Ultimately, with a rapidly changing energy environment, PGE needs to be involved with, and provide support for, projects of increasing importance such as demand response and carbon offsets/reductions, which provide numerous quantitative and qualitative long-term benefits.

Q. Have PGE's R&D projects provided benefits to customers?

A. Yes. As noted above, however, these projects typically involve a long-term effort, and benefits may not be realized for some years. Examples of benefits from prior R&D projects include:

- As part of the Wind Research Cooperative (Cooperative), PGE supported Oregon State University (OSU) in the 1990s. The Cooperative consisted of several utilities, state and federal agencies, and wind power developers and manufacturers.[4] The Cooperative focused on resolving technical issues that were obstacles to wind development in the Pacific Northwest. Some of the research areas included: wind turbine aerodynamics, structural dynamics, power electronics, wind resource evaluation, wind integration, and wind forecasting. Cooperative research work in the 1990s laid the foundation and education for rapid Northwest wind development and the present significant build out of the wind power resources in the region. Today, most of the utility sponsors of the Cooperative have major wind developments in the Pacific Northwest. Northwest wind developers have, and continue to use, the OSU wind data base extensively in defining wind resources for development.
- The purpose of our "Oil Spill Containment" or "Oil Absorbing Mat" project was to design, test, and evaluate a "Containment Mat" that could be used to absorb oil and otherwise contain small spills from leaky transformers, radiators and other oil filled electrical equipment found in substations and other areas of distribution systems. As a result, PGE is better equipped to address oil spills through an oil

[4] The founding members of the Cooperative included Pacific Power, Portland General Electric, Idaho Power, Puget Power, Eugene Water and Electric Board, U.S. Windpower, Zond Systems, Altamont Group, NRG Systems, Oregon Department of Energy, and Bonneville Power Administration. Additional members were added including Seattle City Light, Sea West, FloWind Corp., Kenetech Windpower, and the Northwest Power Planning Council.

spill control system that PGE is installing in our substations and in several customer-owned substations.

- Our Plant Information software project modified a program used by oil companies and a few utilities for system monitoring by converting it to a Web-based platform. This system, along with a real-time, gas-in-oil transformer monitor project, subsequently identified a 28 MVa transformer that was overheating, which avoided over $1.0 million in repairs.
- Selective Catalytic Reduction addresses emissions from dispatchable standby generators so they can meet air permitting requirements.
- Ultra-Low Sulfur Diesel and Catalytic Device testing on PGE trucks have a goal of reducing emissions from PGE's fleet.

D. OPUC Fees

Q. Why are costs for OPUC Fees expected to change from 2007 to 2009?

A. OPUC fees are projected to increase from $3.4 million in 2007 to approximately $5.4 million in 2009 due to a change in the way the fee is calculated, that was enacted by the Oregon Legislature in 2007. In recent years, the OPUC fees have been calculated by a formula based on a rate per kilowatt-hour delivered to the retail electric customer. The new methodology is based on gross operating revenues. Thus, we have adjusted OPUC Fees to reflect a 0.3125% rate applied to gross revenues.

Q. Has this increase already been reflected in rates?

A. Yes. Commission Order No. 07-392 authorized the increase to implement House Bill 2053. PGE applied this change temporarily in Tariff Schedule 105, effective January 1, 2008. The

2009 forecast incorporates this increase into base rates, and thus, the corresponding Schedule 105 component will be set to zero in 2009.

E. WECC Membership

Q. Please explain the increase in the WECC membership cost from 2007 to 2009.

A. Costs for the WECC memberships are forecasted to increase from approximately $550,000 in 2007 to approximately $930,000 in 2009. This increase is in two parts: 1) a 48% increase in fees from 2007 to 2008, and 2) another 12% increase from 2008 to 2009. The WECC has indicated that the reason for this significant increase is higher labor and O&M costs due to new compliance rules adopted by the North American Electric Reliability Corporation (NERC). The new rules ensure reliable planning and operation of the bulk power system, which consists of the power plants, transmission lines, substations, and related equipment and controls that generate and move electricity in bulk to points from which local electric companies distribute the electricity to customers.

Q. What benefits does WECC provide its members?

A. WECC coordinates and promotes electric system reliability, supports efficient competitive power markets, assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members.

WECC and the nine other regional reliability councils were formed due to national concerns regarding the reliability of the interconnected bulk power systems, the ability to operate these systems without widespread failures in electric service, and the need to foster the preservation of reliability through a formal organization. Originally, membership in WECC was voluntary and open, and it continues to be extremely important for the region's interest in the reliability of interconnected system operation and coordinated planning. More recently, however, the FERC has delegated certain audit and penalty authority to WECC with regard to system reliability, resource adequacy, and transmission capacity in the region. Consequently, PGE's membership in WECC is no longer optional.

F. Business Continuity and Emergency Management

Q. What costs are associated with business continuity and emergency management?

A. PGE forecasts an increase of approximately $350,000 in 2009 due to the creation of the Business Continuity and Emergency Management Department in mid-2007. This function was established to support on-going evaluation, mitigation and response to significant events that may adversely affect service to customers, company assets, and employees. This includes providing planning support to recover critical functions as quickly as possible, in compliance with all regulatory requirements. Two positions were created in 2007 and two will be added in 2008. The costs also include training materials and other expenses to support the department's activities.

Q. Why does PGE need this department now?

A. PGE needs this department because the electrical system is a critical system that needs to be restored.[5] In addition, the frequency and magnitude of man-made and natural disasters has increased in recent years, and the impact of these disasters on companies has greatly increased due to technological advances and the complex nature of the supply chain. In response to this increasing risk and the need for PGE to continue to provide a critical infrastructure service to our customers and regional partners, we are committed to take an

[5] The U.S. Department of Homeland Security has established a National Infrastructure Protection Plan (NIPP) which is a comprehensive risk management framework defining critical infrastructure protection roles and responsibilities for government and private industry. Energy infrastructure has been identified as one of the top 13 critical infrastructures necessary to provide social normalcy and requiring mitigation for "significantly strengthening vital infrastructure and reducing vulnerability to all hazards."

all-hazards approach and make PGE more resilient. This department will establish business continuity plans and procedures; conduct risk and business impact assessments; develop training programs and materials; and establish and operate emergency operations center functions and facilities needed to effectively prepare for, respond to, and recover from, a variety of emergency events.

G. Sherman County Strategic Investment Program Payments

Q. Please describe the Strategic Investment Program (SIP) agreement PGE has with Sherman County in lieu of property taxes.

A. PGE has reached an SIP agreement with Sherman County associated with PGE's development of the Biglow Canyon wind farm. This agreement includes property tax abatement for PGE based on the economic benefits of the wind farm development (e.g., the creation of new full-time positions and the potential for increased utilization of local businesses). The agreement also includes payments by PGE for specific Sherman County programs (e.g., school and county renewable energy programs, library funding, and community college funding) that partially offset the lower property taxes. In 2009, PGE's partially offsetting payments are approximately $700,000 and are included in the test year forecast under A&G.

Q. Has this increase already been reflected in rates?

A. Yes. All costs associated with Biglow Canyon, including the SIP agreement, were approved by Commission Order No. 07-573, and included in rates through Tariff Schedule 120, effective January 1, 2008. The 2009 forecast incorporates these costs into base rates, and the corresponding Schedule 120 component will be set to zero in 2009.

H. IT Costs

1. Overview

Q. How much does PGE forecast that allocated IT costs will increase for A&G?

A. Between 2007 and 2009, PGE forecasts that IT allocations to A&G will increase by approximately $1.0 million.

Q. Do these represent all the IT charges to A&G or all the IT costs for PGE?

A. No. A&G receives two types of IT costs: 1) directly charged and 2) allocated. These A&G costs represent only a portion of the total IT costs that are incurred for PGE as a whole.

Q. How are PGE's total IT costs forecasted to change from 2007 to 2009?

A. PGE forecasts that total IT expenses, including incurred charges and loadings will increase from $39.9 million in 2007 to $45.9 million in 2009. These costs are comprised of the following:

Table 2
Total IT Costs ($ Millions)

Category	2007 Forecast	Test Year 2009	Variance 2007-2009
Direct Charges	$14.5	$16.6	$2.1
Allocated Charges	25.4	29.3	3.9
Total IT	$39.9	$45.9	$6.0

Q. How are IT costs charged to the specific functional areas?

A. As noted above, PGE's IT costs consist of two categories: directly charged and allocated. Directly charged costs are related to systems that apply to specific functional areas, such as production, transmission, or distribution. These costs are charged directly to specific expense ledger accounts related to those functional areas. Other IT work that is performed on voice, data, network, communications, and office systems are not the direct responsibility of one specific functional area. Instead, these costs apply broadly to all of PGE activities and departments and are first charged to a balance sheet ledger account and then allocated to the expense ledger accounts of the various functional areas. Labor charges to the balance sheet ledger account have labor loadings applied per PGE's loading and allocation policies, which are submitted annually to the OPUC Staff as an attachment to our Affiliated Interest Report.

Q. In general, what do the cost increases from 2007 to 2009 represent?

A. In general, these increases represent two types of costs: 1) an increased base of systems to be maintained and 2) O&M costs associated with the replacement of aging, non-supported systems by newer, more efficient systems.

Q. Why is it important to replace aging systems?

A. There are two problems with aging systems. First, when systems reach the end of their effective lives, vendors often no longer support them, so maintenance is no longer feasible or is very costly. In these cases, the most practical, least-cost solution is often to install a new system. Second, in the rapidly changing IT environment, aging systems often do not provide the efficiency or the functionality of newer systems. In these instances, the IT department evaluates the trade off between the potentially higher costs of the new systems and the benefits they provide.

Q. What examples do you have of systems at the end of their useful lives?

A. One example is the telephone technologies with interactive voice response, voicemail, call routing, call recording, and reader board systems used at PGE's customer contact center. The version of these products we are currently using has been discontinued and unsupported by the manufacturers and/or distributors. PGE's approach is to replace them with an integrated solution and to implement it in a compressed timeframe. The IT market has moved to bundled application suites and a single system provides significant advantages.

Implementation costs and time can be reduced since a limited number of vendor solutions are being installed and the products have been tested to work well together. This project will also provide improvements to current PGE processes by providing enhanced call routing and network capabilities for outage and customer service. It will also provide flexibility for remote/mobile agents and improved access for call recording retrievals.

Another example is the conversion of applications that are written in Microsoft's Visual Basic 6 (VB6) programming language to a newer product. VB6 will soon become an unsupported product by Microsoft and there are over 20 applications/modules within PGE's distribution function that are written in VB6 and need to be rewritten. Reasons we need to update these programs include:

- Microsoft has stopped releasing service packs for VB6 development tools, so any existing or new bugs will not be fixed in the future.
- Newer development tools allow for better operational support.
- As programming languages age, it is more difficult to find trained personnel to support these applications.
- Newer programming languages and other development tools provide better integration, better testing and diagnostic tools, and usually a more efficient operating environment.

Q. What is PGE's strategy for implementing new systems to take advantage of efficiencies or increased functionality?

A. PGE utilizes the following concepts for this strategy:

- Optimize infrastructure by consolidating systems wherever possible;
- Reduce and integrate applications;

- Improve efficiencies by standardizing programming languages, applications and tools wherever possible; and
- Leverage the Web to rapidly deploy new functionality and enable self-service publishing of information by client groups and enhance the sharing of data between systems.

Q. Do you have any examples of implementations that demonstrate these concepts?

A. Yes. A current example is WebSphere, which is a suite of application integration tools that PGE adopted in 2006. WebSphere provides an integration framework to share data across applications and to ultimately reduce the development and on-going maintenance costs that are otherwise incurred to interface applications directly with one another. WebSphere facilitates the integration of systems, allows data to be shared in a consistent format, supports the reusability of code and helps provide common user interfaces.

Q. How has PGE been applying WebSphere?

A. WebSphere tools are flexible and can be utilized in a number of environments. PGE is currently using WebSphere to integrate functions within the automated meter exchange process and to develop new web-based transactions for Renewable Power enrollments, cancellations, and changes, and is beginning to use WebSphere to integrate the Stop, Start, Move-In and Move-Out service requests. WebSphere allows transactions to be initiated by both external customers as well as PGE employees. PGE can use the WebSphere tool to create efficient front-end interfaces that are specific to PGE's requirements, thereby shortening transaction processing times and optimizing core customer processes. For the Renewables enrollment process, PGE has been able to replace 36 manual steps with an automated process, which is more efficient and will result in faster processing with fewer errors. The strategic direction of PGE's IT department is to use the WebSphere for new applications as well as migrating existing applications to this platform over time.

Q. What are the benefits of WebSphere?

A. The key benefits that WebSphere infrastructure is expected to deliver are real-time integration capability, increased performance, consistent look to our systems, and increased reuse of application code. These benefits will eventually translate to reduced development time and more efficient maintenance of application code.

Q. Does PGE pursue cost savings in its efforts to maintain existing systems?

A. Yes. A major example of this is PGE’s customer information system (CIS), Banner. In 2007, PGE discontinued the vendor’s maintenance agreement for Banner after determining that it was more cost effective to bring the system expertise in-house. As a result of this change, PGE reduced annual maintenance costs by approximately $650,000. We accomplished this by eliminating the annual maintenance agreement of approximately $1.1 million and replacing it with PGE labor of approximately $450,000. In addition to the financial benefit, PGE is able to develop a skilled internal workforce to address critical maintenance and system modification activities without having to rely on outside resources.

2. Cost Drivers

Q. What are the principal drivers for increases in total IT costs from 2007 to 2009?

A. The principal drivers for IT are labor (which has three components), software/hardware maintenance costs, and other strategic initiatives. Specifically, costs for these components increased as follows:

- As with A&G, wages and salaries increased by approximately 4.5% for IT, which is a labor intensive operation. This represents a $1.5 million increase, of which $650,000 applies to direct charges and $900,000 applies to allocated costs.
- FTEs increased from 273.6 in 2007 to 286.9 in 2009, which represents a 2.4% average annual increase and $1.2 million. Of this increase, $700,000 applies to direct charges and $450,000 applies to allocated costs.
- Labor loadings on allocated costs increased by approximately $600,000 from 2007 to 2009. This increase is, ultimately, a function of the labor increase listed above and the increase in employee benefits and support costs that are described primarily in PGE's compensation testimony, PGE Exhibit 800.
- Software and hardware maintenance costs increased by approximately $900,000 from 2007 to 2009.
- Strategic initiatives account for approximately $1.2 million of the increase.

Q. What are the reasons for the increase of 13 FTEs?

A. Five new positions are needed to support PGE's CIS. As discussed above, PGE discontinued the vendor's maintenance agreement for Banner in April 2007, after determining that it was more cost effective to bring the system expertise in-house. Three of these positions were filled in 2007 and the other two will be filled in 2008. Another five FTEs relate to open positions in 2007 and represent positions that are difficult to fill because of the specific skill sets required. PGE expects to fill these positions beginning in 2008. PGE also forecasts an increase of two new positions to support the WebSphere technology (described above). PGE hired a WebSphere Architect in 2007 and will hire a system administrator in 2008.

Q. To what applications or systems do the maintenance costs apply?

A. The $900,000 increase in maintenance costs applies to the following systems and applications:

- Approximately $400,000 is for increasing maintenance costs for corporate-wide software and hardware. The increase is primarily due to hardware maintenance costs for PGE's expanding computing environment, which includes data storage growth, connectivity (disk and backup), and processor upgrades. Additional applications require more computer hardware, which results in increasing maintenance costs for the associated devices.
- Approximately $350,000 represents annual maintenance for the new integrated technologies system at PGE’s customer service center to be completed in 2008.
- Approximately $210,000 represents annual software maintenance for the new Energy Management System in PGE’s transmission department. This system is scheduled to be operational in 2008 and replaces the existing legacy system. The new system meets emerging reliability and cyber security requirements from FERC and NERC that are not supported in the current system.
- Approximately $480,000 is for increases in the maintenance costs of other existing software applications such as PeopleSoft, Masterpiece, Excelergy, Energy Bookrunner, Market Manager, and Gas Management System, which support human resources, accounting, energy service supplier operations, power supply, and risk management applications. Maintenance increases are typically contractual and range from 5% to 15% annually, with an average increase of

approximately 8%. PGE's contract administration group within IT negotiates with vendors to minimize maintenance costs wherever possible.

Q. The above-listed increases total more than $900,000. Did PGE reduce IT maintenance costs for certain applications?

A. Yes. As noted above, CIS maintenance is now in-house because it is more cost effective than the vendor maintenance agreement. Consequently, the 2007 forecast includes approximately $500,000 in partial-year CIS vendor maintenance costs that do not exist in 2009.

Q. By how much are costs forecasted to increase because of strategic initiatives?

A. There are three components to the strategic initiatives that account for the $1.2 million increase from 2007 to 2009: WebSphere Development Tools, additional user licenses for Change Management, and the conversion from VB6.

Q. What are the costs associated with WebSphere?

A. Approximately $1.0 million of the forecasted increase from 2007 to 2009 is for WebSphere Development Tools. As noted above, WebSphere is a suite of application integration tools adopted by PGE in 2006 to provide an integration framework to share data across applications and to ultimately reduce the development and on-going maintenance costs that are otherwise incurred to interface applications directly with one another. Although WebSphere was selected as a strategic toolset for the department, we are only acquiring software licenses as they are needed to minimize costs.

Q. What are the increases attributable to Change Management and VB6?

A. Approximately $100,000 represents additional user licenses for the Change Management application because PGE anticipates that the majority of IT staff will use this database application to track changes to hardware, software applications, and other computer utilities and tools by 2009. Approximately $70,000 is to support the conversion of applications that are written in VB6 to new languages.

III. Additional A&G Costs

Q. Are there additional A&G costs that PGE will include in its errata filing?

A. Yes. As noted in PGE Exhibit 100, compliance requirements from the State of Oregon, FERC, NERC, and the WECC are increasing significantly in relation to many aspects of PGE's operations. PGE has already included most of these in our 2009 test year revenue requirement and we have described them in the respective Exhibits (e.g., 7.5 additional FTEs needed to comply with FERC Orders 890 and 890-A – see PGE Exhibit 400). In addition to these FTEs and costs, PGE has identified the following positions necessary to meet other recent FERC requirements at an incremental cost of approximately $630,000 above levels already included in the 2009 forecast.[6] Because these costs are not currently included in PGE's test year revenue requirement, they will be part of the errata filing that we expect to make in late March or early April 2008.

- Two positions in PGE's FERC Compliance department:
  - A FERC compliance analyst to manage company-wide projects related to FERC, NERC, and WECC, and to develop PGE's auditable compliance with mandatory reliability standards; and
  - A specialist to assist with PGE's responses to emerging FERC issues and initiatives. This will include drafting, editing, and electronically filing PGE pleadings and interventions.
- A FERC Tariff Analyst, in PGE's Power Operations group, to coordinate all aspects of FERC-related orders for both power and natural gas. The analyst's responsibilities will include documentation, monitoring industry forums, develop

6 PGE included 2.5 approximate positions in the 2009 forecast but has now more clearly defined the specific positions for the FERC compliance and will include only the increment in the errata filing.

written policies and procedures, coordinate training and PGE self-audits, and work with IT on automated solutions.

- Three positions in Transmission and Reliability Services (T&R):
  - One supervisor to administer the open access tariff, interconnection requests, FERC Order 890, regional representation, and FERC governance;
  - One specialist to perform billing and reporting; FERC, NERC, WECC data collection reporting; process service agreements, and address energy imbalance issues; and
  - One specialist to interpret and implement new orders, rules, and regulations, and coordinate: 1) efforts of T&R's subject matter experts, 2) the development, documentation, and implementation of resulting business policies and procedures, and 3) T&R's development, documentation, and implementation of relevant policies and procedures.
- One engineer in PGE's Transmission and Distribution Operations and Planning group to perform studies to ensure PGE's compliance with NERC requirements. This position will also represent PGE in coordinating NERC activities with other constituents such as NWPP, BPA, PacifiCorp, and WECC members.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
501	Summary of A&G Costs and FTEs.

Category	$ Millions 2007 Forecast	2008 Budget	2009 Test Year	Delta 2009-2007	Annual % Increase	FTEs 2007 Forecast	2008 Budget	2009 Test Year	Delta 2009-2007	Annual % Increase
Major Functional Areas										
Facilities and General Plant Maintenance	10.7	10.9	11.1	0.5	2.2%	13.9	15.1	15.1	1.2	4.2%
Accounting/Finance	8.2	9.0	9.2	1.0	6.0%	81.3	79.9	79.4	(1.8)	-1.1%
HR/Employee Support (net of capital allocs.)	4.4	5.0	6.5	2.1	21.4%	101.1	98.7	102.0	0.9	0.4%
Insurance / I&D	9.6	10.9	11.2	1.5	7.6%	6.5	6.4	7.0	0.5	3.4%
Legal	5.9	6.3	6.0	0.1	0.6%	26.5	30.4	29.5	3.0	5.5%
Regulatory Affairs	2.3	2.6	2.8	0.5	10.8%	29.2	30.0	30.0	0.8	1.3%
Corporate Governance	2.8	3.2	3.4	0.6	10.4%	18.8	18.0	19.0	0.2	0.7%
Business Support Services	2.1	2.3	2.4	0.4	8.3%	8.3	8.0	8.0	(0.3)	-1.8%
Environmental Services	0.9	0.9	1.2	0.3	14.4%	20.6	22.6	24.0	3.4	8.0%
Corporate R&D	0.3	0.3	1.0	0.7	95.9%	0.0	0.0	0.0	-	0.0%
Contract Services/Purchasing	1.1	1.2	1.3	0.2	10.4%	19.9	21.2	21.2	1.3	3.2%
Security and Business Continuity	0.8	1.1	1.3	0.5	29.3%	5.6	7.2	9.0	3.4	27.1%
Corp Communications/Public Affairs	1.4	1.9	2.1	0.7	23.9%	22.2	21.2	21.2	(1.0)	-2.2%
Load Research	0.1	0.2	0.2	0.1	29.9%	0.0	0.0	0.0	-	0.0%
Hydro Licensing	0.4	0.5	0.6	0.2	21.6%	0.0	0.0	0.0	-	0.0%
Governmental Affairs	0.9	0.9	1.1	0.1	6.5%	12.1	13.0	13.0	0.9	3.5%
Subtotal	51.9	57.4	61.5	9.6	8.8%	365.9	371.8	378.3	12.4	1.7%
Other A&G Costs										
IT: Direct & Allocated	6.9	7.8	8.3	1.4	9.8%	273.6	284.4	286.9	13.4	2.4%
Other Service Providers to A&G	0.3	0.6	0.4	0.1	10.7%					
Benefits (net of capital allocs.)	29.5	28.9	32.3	2.8	4.6%					
PTO Loadings to A&G	3.8	4.0	4.2	0.4	5.6%					
Corporate Incentive Plan (net of capital allocs.)	6.7	5.3	6.1	-0.6	-4.9%					
Management Incentive Plan	8.4	5.0	5.2	-3.2	-21.3%					
Stock Incentive Plan	2.4	3.2	2.8	0.4	7.2%					
Variable Pay - Coyote & Trojan	0.5	0.4	0.5	0.0	-3.3%					
Regulatory Fees	4.3	5.7	6.6	2.3	23.8%					
Other Membership Costs	1.1	1.5	1.5	0.4	16.6%					
Miscellaneous	-0.2	-4.4	-0.1	0.1	-22.8%					
Subtotal	63.8	58.1	67.8	4.0	3.1%	639.5	656.2	665.3	25.8	2.0%
A&G Offsets										
Capitalized A&G	-6.7	-6.7	-6.9	-0.2	1.7%					
Duplicate Charge Offset (a)	-1.8	-1.8	-1.8	-0.1	1.8%					
TOTAL A&G (b)	**107.2**	**107.0**	**120.5**	**13.3**	**6.0%**	**639.5**	**656.2**	**665.3**	**25.8**	**2.0%**

Notes:
(a) The duplicate charge offset reverses PGE's charges to itself for electric power.
(b) Variances due to rounding

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HAWKE

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Transmission & Distribution

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Hawke

February 27, 2008

Table of Contents

I. Introduction

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

A. My name is Stephen Hawke. I am Senior Vice President of Customer Service and Delivery. My qualifications appear at the end of my testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain PGE's 2009 test year Transmission and Distribution O&M expenditures, and how they support PGE's goal of adding customer value through operational excellence and improvement.

Q. Please summarize PGE's Transmission and Distribution O&M costs, full-time equivalent (FTE), and capital expenditures from the 2007 forecast through the 2009 test year forecast.

A. Table 1 below summarizes this information[1]:

Table 1
Summary T&D Changes ($ Million)

	2007 Forecast	2008 Budget	2009 Test Year
Transmission O&M Expenses	$9.5 [2]	$10.8	$11.6
Distribution O&M Expenses	$59.4	$61.9	$67.9
Transmission FTEs	25	26	27
Distribution FTEs	1,006	1,033	1,038
Transmission Capital Additions	$50.0	$15.2	$8.5
Distribution Capital Additions	$127.7	$129.2	$131.0

Q. Does the OPUC set goals for Transmission and Distribution?

A. Yes. PGE consistently meets the OPUC weighted-average goals for outage frequency and momentary outages. The target outage frequency goal (outages lasting 5 minutes or more) is no more than one per customer per year. The actual results have been 0.73, 0.77, 0.81 and

[1] The 2007 forecast represents nine months of actuals and three months of remaining budget.
[2] The 2007 forecast included an out of period credit of approximately $243,000 that applies to 2006 rather than 2007.

0.94 outages per customer, per year for 2003, 2004, 2005, and 2006. The target goal for momentary outages (less than 5 minutes) is no more than three per customer per year. The actual results have been 2.15, 1.97, 1.76, and 1.64 for the years 2003, 2004, 2005, and 2006.

PGE's outage goals of less than 1.0 and 3.0 are the most stringent for investor-owned utilities in Oregon. PGE submits annual service quality measure (SQM) reports, which contain outage and other results. The Commission Staff audits our SQM reports in detail and enforces the defined performance levels.

Q. How is the remainder of your testimony organized?

A. First, I discuss Transmission O&M and the current changes in the industry. Second, I discuss Distribution O&M. Third, I discuss Distribution labor trends and current changes that determine operational costs. Finally, I discuss the Distribution programs and the increased activity in those programs.

II. Transmission

A. Transmission O&M Expenses

Q. Please identify the changes in O&M costs and FTEs from 2007 to the 2009 test year forecast that are associated with Transmission.

A. As Table 2 below summarizes, Transmission O&M expenses increase approximately $2.1 million, and FTEs increase by approximately three, during this time.

Table 2
Transmission Expenses ($ Million) and FTEs

	2007 Forecast	2008 Budget	2009 Test Year
Transmission O&M Expenses	$9.5	$10.8	$11.6
Transmission FTEs	25	26	27

Q. What are the major drivers of the increase in Transmission O&M expenses?

A. As shown in Table 3 below, there are two major drivers of the increased costs: 1) labor, primarily wage escalation related to union contracts and FTE growth, and 2) Information Technology, due to increased software maintenance costs and allocations.

Table 3
Transmission O&M Drivers of Cost Changes from 2007 Forecast to 2009 Test Year Forecast

Cost Driver	$ Million
Labor Increases	0.5
Information Technology	0.5
Regional Planning Entity & Professional Services	0.3
WECC Reliability Centers	0.2
Unscheduled Flow Mitigation Plan	0.1
Total	**1.6**

I explain each of these drivers in more detail below.

1. Transmission Labor Increases

Q. Table 3, above, shows labor increases and Information Technology as the two largest drivers of higher costs. Please discuss why labor costs increase approximately $500,000.

A. The majority of the higher cost, approximately $400,000, is due to wage escalation, driven by labor market forces and increased union contract costs. Section III, Part B below, discusses the union contract in further detail. The remainder of the increase is related to the addition of new FTEs.

Q. Why is PGE hiring two new FTEs related to Transmission activity?

A. PGE hired a compliance engineer in response to greater regulation from the Federal and State governments to ensure accurate recording and reporting of information, and we will need to hire one more in the next six months. Transmission, and PGE as a whole, is now required by the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), and the Western Electricity Coordinating Council (WECC), to produce documentation to demonstrate that we are in compliance with over 500 individual measures and processes. If we cannot timely achieve compliance, we must write mitigation plans stating when and how we will achieve it. Failure to comply exposes PGE to financial risk. In addition, the compliance engineer will have to review FERC orders and issuances, the latter of which can number up to 100 per business day. This is not unique to PGE - virtually every transmission owner in the country is going through the same changes to meet the new requirements.

Q. Besides the compliance engineers, PGE's Transmission shows a need for an additional FTE. Please explain.

A. The remaining FTE is related to succession planning, to learn needed skills while on-the-job, prior to retirements within the department. With all the new Federal regulatory requirements, transmission engineers and planners are becoming a very scarce and valuable resource. The ability to develop our own internal resource is important as skilled external resources may not be available at a reasonable cost in the market. This is increasingly a focus, not only for PGE, but for the industry as a whole (see also PGE Exhibit 800, Compensation).

2. Information Technology (IT)

Q. Please discuss the second largest driver, IT.

A. Transmission IT costs increase by approximately $500,000 from 2007 to 2009. This increase consists of two components: directly charged costs and allocated costs. Directly charged costs increase by approximately $300,000 and are primarily due to annual software maintenance for the new Energy Management System (EMS). This system is scheduled to be operational in 2008 and replaces the existing legacy system that is over 12 years old. The new system meets emerging reliability and cyber security requirements, established by the FERC and NERC, that are not supported in the current system. The EMS will also introduce a new Quality Assurance System testing platform to ensure compliance with new NERC cyber security requirements.

Also in 2008, an Operator Training Simulation and new applications for contingency analysis will be available to assist dispatchers with real-time switching operations. The new features in 2008 again address new NERC requirements associated with training and real-time operations.

Q. How are allocated IT costs forecasted to change for Transmission?

A. IT allocations are forecasted to increase by approximately $225,000. These allocations are discussed in PGE Exhibit 500, Section II.

3. Other Factors

Q. What other factors contribute to the remaining $600,000 increase in Transmission O&M?

A. As shown in Table 4 below, there are three other factors: regional transmission planning, WECC requirements, and unscheduled flow mitigation, which I describe further below.

Table 4

Other Transmission O&M Cost Drivers

Cost Driver	**$ Million**
Regional Transmission Planning & Professional Services	0.3
WECC Reliability Centers	0.2
Unscheduled Flow Mitigation	0.1
Total	**0.6**

Regional Transmission Planning and Professional Services

FERC Order No. 890 directed PGE, as a transmission provider, to establish a coordinated, open, and transparent planning process with its transmission customers, interconnected utility systems, and others, to ensure that PGE's transmission system is planned to meet the needs of both PGE and its transmission customers on a comparable and non-discriminatory basis, and ensure the reliability of the transmission grid.

To accomplish these goals, PGE must now make its own transmission planning processes transparent and also coordinate and actively participate in sub-regional and regional planning with other affected utilities and interested persons.

PGE forecasts approximately $200,000 for its participation in regional Transmission planning. In addition, PGE forecasts an additional $100,000 in professional services, to actively engage in coordination planning and studies to be conducted at the sub-regional and regional levels.

WECC Reliability Centers

PGE is a member of WECC and as part of our membership in the WECC, PGE's costs will increase by approximately $200,000 for fees assessed to help construct and support new reliability centers.

Unscheduled Flow Mitigation (UFM)

UFM is the mitigation of transmission overloads due to unscheduled line flow on Qualified Paths. PGE's costs are expected to increase by $100,000 because WECC requires us to develop an UFM plan to address this issue. WECC members must comply with requests from Transmission Path Operators to take actions that will reduce unscheduled flow on one or more Qualified Paths in accordance with the "WECC Unscheduled Flow Procedure Summary of Curtailment Actions."

Q. What capital work is PGE planning?

A. PGE's Transmission and Distribution Capacity Expansion Project is a multi-year project to add transmission capacity to PGE's system by upgrading key components of our distribution system to convert them to transmission voltages. This is an effort to increase our system's effectiveness and efficiency and to provide for load growth.

Q. Why are PGE's capital addition costs approximately $50 million in 2007 and only $15.2 million and $8.5 million in subsequent years?

A. The decrease in capital additions from 2007 to 2009 is reasonable because PGE had two major capital projects in 2007, the Port Westward and the Biglow Canyon Plants. Both of these projects involved considerable transmission capital investment.

III. Distribution

A. Distribution O&M Expenses

Q. Please identify the changes in O&M costs and FTEs from 2007 to the 2009 test year forecast that are associated with Distribution.

A. As Table 5 below summarizes, O&M expenses increase from approximately $60 million to $68 million, and Distribution FTEs increase from approximately 1,006 to 1,038.

Table 5
Distribution Expenses ($ Million) and FTEs

	2007 Forecast	2008 Budget	2009 Test Year
O&M Expenses	$59.4	$61.9	$67.9
FTEs	1,006	1,033	1,038

Q. What are the major drivers of the increase in Distribution O&M expenses?

A. As Table 6 below summarizes, the two major drivers of increased O&M expenses are: 1) approximately $3.8 million related to labor costs and FTE growth, and 2) approximately $2.0 million in Tree Trimming costs.

Table 6
Distribution O&M Drivers of Cost Changes from 2007 Forecast to 2009 Test Year Forecast

Cost Driver	$ Million
Labor Increases	3.8
Tree Trimming	2.0
Information Technology	1.3
Locating Cost Increases	0.7
FITNES Program for Poles	1.1
Material Cost Increases	0.5
Safety (Arc Mitigation)	0.4
Porcelain Insulator Replacement	0.3
Total of Cost Drivers from 2007 to 2009	**10.1**

I explain each of these drivers in more detail below.

B. Distribution Labor Increases

Q. Why are Distribution labor costs higher by approximately $3.8 million?

A. There are two primary components to the cost increases in labor: 1) escalation of costs related to the collective bargaining agreement, including supply and demand of qualified applicants creating a premium for labor, and 2) more FTEs.

Q. Besides wage escalation, why is the supply and demand of qualified applicants increasing union contract costs?

A. Greater demand for, and a shortage of qualified workers, is creating a premium for skilled line workers. Some utilities now pay signing and retention bonuses for skilled labor. While PGE has not generally implemented this practice, we expect the cost of skilled labor will continue to increase.

PGE Exhibit 800, Compensation, explains in more detail how the cost to attract and retain skilled labor is increasing due to a shortage of qualified applicants in the industry. This shortage is due, in large part, to the retirement of an experienced segment of the workforce and is particularly acute for skilled line workers.

Q. PGE shows an increase of 32 FTEs from 2007 to the 2009 test year forecast. Please explain.

A. The primary reason for the growth in FTEs is the difficulty filling positions in the 2007 forecast, which distorts the increase of FTEs in subsequent years.

Q. Describe the factors contributing to the vacancies in the 2007 forecast?

A. A nationwide shortage of qualified applicants, as well as normal attrition, and the length of time to train linemen (apprenticeships are three-year programs with an 18-month waiting list) all contribute to vacancies in the 2007 forecast.

Q. What will PGE do if it cannot hire all of the forecasted positions?

A. PGE must budget FTEs accordingly in order to quickly hire skilled labor in a competitive labor market. If PGE is unable to fill those vacancies, contract labor will be utilized to fill the gap.

Q. Did PGE use contract labor to fill gaps due to vacancies in 2007?

A. Yes. We must complete the work necessary to maintain, expand, and improve the distribution system. In 2007, we used contract labor to fill gaps due to vacancies. However, the use of contract labor can distort changes in FTEs in subsequent periods as we continue to search for qualified candidates to fill vacant positions.

C. Distribution Programs

Q. Please describe the programs that are driving Distribution O&M costs higher?

A. The primary areas that are increasing costs in Distribution O&M are:

- Tree Trimming (more frequently);
- Facility Inspection and Treatment to the National Electric Safety code (new cycle for "FITNES");
- Utility Underground Locating (more "Locates"); and,
- Porcelain Insulator Replacement Project (new project).

1. Tree Trimming

Q. What is PGE's current practice with respect to tree trimming cycles?

A. PGE's practice is a two-year cycle in urban areas and three years in rural areas. Previously, our practice was to trim trees in three-year cycles in both areas.

Q. Why have tree trimming costs risen by approximately $2.0 million from the 2007 to 2009?

A. PGE contracts for most of its tree trimming labor. The primary reason costs have risen is higher contract rates beginning in 2007.

Q. Why have contract costs risen?

A. There is significant turnover of journeymen and foremen in the tree trimming trade due to retirements, advancements, and movement to utility linemen positions. The linemen trade actively recruits from the tree trimming trade to fill vacancies because tree trimmers possess many of the same qualifications, skills, and safety training as linemen, but, in general, earn less. The turnover in tree trimming personnel increases costs by decreasing productivity and increasing workload. In addition to this loss of productivity, contractors (and PGE) are experiencing increased material and fuel costs which contribute to higher contract costs.

Q. What is PGE's contractor doing to help mitigate the shortage in available workers?

A. To help mitigate the shortage in available workers, PGE's tree trimming contractor is:

1. Expanding the recruitment geographic base: recruiting workers in states with high unemployment, such as Michigan, as well as in cities where tree trimmers face layoffs, such as Chicago, Louisville, Phoenix, and Columbus.
2. Expanding the normal recruitment demographics: running employment ads in Spanish newspapers in San Antonio and Houston, Texas (where labor rates for line clearance tree trimmers are the lowest in the nation) because Latino and Hispanic groups are the fastest growing labor groups in the tree trimming trade.
3. Going beyond immediate need: creating a Pre-Apprenticeship Program and a line clearance tree trimming curriculum at Clackamas Community College at the Wilsonville Training Center location.

Q. Has PGE recently bid its tree trimming work?

A. Yes. In 2006, PGE asked its existing contractor at the time and two other contractors to submit bids for PGE's tree trimming work. Two of the three contractors were comparable in price, so PGE split the work between the two lower priced contractors (our existing contractor and one of the new contractors), allowing us to compare their performance and hopefully increase the productivity of our existing contractor through competition. However, PGE determined the productivity of the new contractor was lower than the existing contractor, and based upon these results we decided to terminate our agreement with the new contractor at the end of December 2006 and continue working with our existing contractor.

2. FITNES

Q. Please describe PGE's FITNES program.

A. The FITNES program inspects, maintains, and repairs all of PGE's 280,000 poles on a 10-year cycle, and all of our underground equipment on a 4-year cycle, including PGE equipment located on large industrial campuses.

Since the program launched in 1987, annual pole rejects have declined from 12% to 0.7%, saving millions of dollars in replacement costs. This is important preventative maintenance that extends equipment life, reduces costs, and increases safety. In addition, FITNES spots potential problems and resolves them before they cause outages.

Q. Why are costs increasing by approximately $1.1 million between 2007 and 2009?

A. The majority of this increase, approximately $900,000, is due to the early completion of the FITNES program in 2007, which lowered the costs for 2007. In 2007, PGE's second 10-year cycle was completed early in the year due to overall efficiencies in the last two years. Thus, 2007 reflects an abnormally low amount of FITNES expense while 2008 and 2009 are normal, full-year levels of expense as we begin our third full cycle.

3. Utility Underground Locating ("Locating")

Q. Why are costs increasing approximately $700,000 for Locating?

A. The reasons for the higher costs are due to higher contract costs and a sharp increase in Locating requests that we expect to continue through 2009. I explain these factors in more detail below.

a. Locating Contract Costs

Q. Why have PGE's Locating contract costs risen?

A. PGE outsources most of its Locating work, and again, contract costs have risen significantly. PGE's Locating contract expired near the end of 2006, and during re-negotiation discussions the contractor significantly raised its rates.

We received another bid from a different contractor whose rates were less than our previous contract. We selected this new contractor, entered into an agreement, and adjusted our 2007 budget to reflect the lower rates. After monitoring and sampling the work reported as "completed on time" by this contractor, PGE discovered that 30% of the Locates were not completed, or not completed within the 48-hour deadline. Based upon this information, and after some attempts at remediation, PGE and the contractor agreed to end the contract prematurely in June 2007.

PGE then began negotiations with its original contractor and, although we were successful in negotiating prices down from their prior bid in 2006, rates were higher than in the previous contract. Thus, 2007 reflects two different contract rates. The higher rate will prevail through 2008 and into 2009. PGE has an option to extend the contract for one year, and we expect to exercise that option.

b. Locating Requests ("Locates")

Q. Why has the number of Locates increased from 2007 to 2009?

A. There are various reasons, but three stand out. First, PGE's service territory is now 40% underground service and, as this portion continues to grow, we expect to receive more Locates. Second, in 2007 the Oregon Legislature approved additional funding for road construction and road widening. Finally, Verizon began a multi-year fiber-optic installation project in March 2005, and this has generated increased Locating requests. The Verizon project originally focused on areas located within PGE's Western Division, in Washington County. However, in 2006, the project expanded to other cities and counties. Because Verizon began offering television service in Washington County in December 2007, the expanded television service is expected to increase the number of service connection Locate requests, in addition to the general increase in Locating requests expected throughout PGE's territory.

Q. Are there any other reasons why you would expect the number of Locates to increase from 2007 to 2009?

A. Yes. We expect increased customer awareness of the "Call Before You Dig" (DIG) hotline to generate more Locate requests. Every operator of underground facilities must subscribe to the Oregon Utility Notification Center, and the recently implemented "811" phone number which became a nationwide number on May 1, 2007. PGE, as part of this nationwide effort to improve public safety, launched a "Call Before You Dig" campaign to increase public safety and awareness about the importance of having utility lines marked before digging.

Because of increased customer awareness, PGE anticipates Locate requests and the number of Locates to continue to rise.

1. Porcelain Insulator Replacement Project

Q. What is PGE's porcelain insulator replacement project?

A. The porcelain insulators in PGE's system have served the system well for over 50 years, but a number are beginning to fail. The failures occur randomly and independent lab tests have not been able to establish any predictable indicators of imminent failure. Due to this inability to predict potential porcelain insulator failures, PGE began a long-term project in 2005 to replace its porcelain post insulators with reliable, lightweight polymer insulators, which will lessen the risk of these events and the associated customer impacts. This program maintains reliability and prevents outages, and is scheduled to continue until 2021.

Q. Why is the program scheduled to continue until 2021?

A. PGE has spread out the replacement project until 2021 to minimize cost increases to customers. PGE believes that its current approach of cycling through the most important lines first and expanding through the distribution system over the next few years is the appropriate approach. However, PGE continuously monitors costs related to failures and if the costs associated with failures of porcelain insulators increase, PGE may need to increase the frequency at which it is replacing them.

D. Other Factors

Q. What other factors are contributing to increasing costs in Distribution O&M?

A. The other areas contributing to the cost increases in Distribution are:

- Information Technology,
- Material cost increases, and
- Arc-flash mitigation.

Q. What changes in Distribution IT costs do you forecast to occur between 2007 and 2009?

A. Distribution IT costs are higher by approximately $1.3 million from 2007 to 2009. This increase consists of two components: directly charged costs and allocated costs. The majority of the increase is related to IT allocations, which are forecasted to rise by approximately $1.0 million, as discussed in PGE Exhibit 500, Section II, part H.

Q. Why are costs in materials increasing approximately $500,000 from 2007 to 2009?

A. Material costs such as metal and oil have risen due in large part to an increased demand for these commodities.[3] This trend of increasing material costs is evidenced nationwide and is expected to be an on-going factor.

Q. Why is Arc-flash mitigation a concern for PGE?

A. PGE is always concerned about safety and providing a safe work environment for its employees. Arc-flash mitigation is a new requirement of the National Electric Safety Code (NESC). Mitigation involves analyzing what is most appropriate for employee safety, promoting awareness, and/or purchasing clothing that helps mitigate the dangers of Arc-flash.

Q. What is Arc-flash and why is it an issue?

A. An arc is produced by a sudden flow of electrical current through ionized air, produced by a flashover or short circuit, resulting in a flash that can cause significant heating and burn injuries.

[3] "The Coming Commodity Clash." (Business Week December 3, 2007 Pg 28).

Arc hazards can result for many reasons, including dropped tools, accidental contact with electrical systems, build-up of conductive dust, corrosion, and improper work procedures. The electrical and safety industries acknowledge that arcing faults can:

- release dangerous levels of radiant heat energy capable of causing severe burns and igniting clothing;
- explode, spraying droplets of molten metal, over a large area;
- produce blast pressure waves, throwing workers and knocking them off ladders; and,
- cause hearing loss from the sound-blast related to the arcing fault.

Q. What is PGE doing to mitigate Arc-flash and what are the costs?

A. PGE is conducting a study in 2008 to determine what the most effective method is to mitigate Arc-flash. In 2009, PGE will budget approximately $361,000, most of which will go to purchasing protective clothing for its employees.

E. Distribution Capital Expenditures

Q. Please describe the Distribution capital work that PGE is planning for 2008 and 2009.

A. Distribution capital additions primarily consist of general pole and line work, customer connections, and the purchase of related transformers and street lighting. This typically amounts to approximately $130 million per year.

Also, in conjunction with our Transmission and Distribution Capacity Expansion Project, discussed in Section II, Part A.3 above, we are also upgrading and improving our Distribution system.

F. Distribution Services

Q. What are PGE's Distribution Services operations?

A. Distribution Services is part of PGE's distribution operations and supports customer-owned facilities at their request. PGE offers its knowledge to primary-metered large companies with high-voltage and electrical distribution needs.

Q. What types of services does Distribution Services provide?

A. The primary services offered are:

- Reliability programs, preventive maintenance, and outage support;
- Engineering - design and construction; and
- Equipment maintenance.

Q. How do these services benefit customers?

A. Large customers may not have the technical expertise and personnel to work with electrical or high-voltage equipment. PGE's experience and equipment, however, alleviates the customer from having to hire and train high-voltage personnel. Proper maintenance of customers' equipment can avoid lost revenue due to breakdowns, prevent outages, increase life expectancy of equipment, improve efficiency, and lower operating costs. An additional benefit is that if PGE has performed these services, when emergency situations arise, PGE can respond more quickly because: 1) we are familiar with the equipment, which may match PGE's equipment, and 2) we can restore service much faster because we typically have standard equipment in stock. Ultimately, this helps ensure that the customer's equipment meets PGE specifications, which because of the interface with PGE's system, has the further benefit of improving PGE's system reliability.

Q. Has PGE included any costs in this rate case for its Distribution Services operations?

A. No. However, we do plan to incorporate the appropriate accounting of this activity in the errata filing that we expect to make in late March or early April 2008.

Q. What will the effect of this be on rates?

A. In 2009, PGE forecasts that operations for Distribution Services will net to zero, (i.e., revenues will be approximately equal to the fully allocated costs). Consequently, there will be no effect on rates.

Q. Where has PGE previously charged these costs and revenues and why are you proposing to change this?

A. Prior to 2009, PGE has charged these costs and revenues "below-the-line" in our non-regulated accounts. We propose to move these costs to "above-the-line" regulated accounts because Distribution Services provides valuable services for customers that should continue on a regulated basis.

IV. Qualifications

Q. Mr. Hawke, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Electrical Engineering and a Bachelor of Science Degree in Mathematics from Oregon State University. I received a Master of Business Administration from Portland State University. I completed additional graduate work at Portland State University in Systems Science and graduated from the Public Utilities Executive course at the University of Idaho. I am a registered professional engineer in the State of Oregon. My employment with PGE started in 1973, as an Assistant Distribution Engineer. I have held positions such as Engineering Supervisor, Chief Underground Engineer, Chief Field Engineer, Sales Manager, Regional Manager in both the Salem and Western regions, Manager of Response and Restoration, General Manager of System Planning and Engineering, and Vice President of System Planning and Engineering. In August 2004, I became Vice President of Customer Service and Delivery. I began my current position of Senior Vice President of Customer Service and Delivery in August of 2006.

Q. Does this conclude your testimony?

A. Yes.

UE ___ / PGE / 700
HAWKE

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Stephen Hawke

February 27, 2008

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I. Introduction

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

A. My name is Stephen Hawke. I am Senior Vice President of Customer Service and Delivery. My qualifications appear in PGE Exhibit 600.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and explain PGE's Customer Service O&M 2009 test year expenses of approximately $73.7 million.

Q. What is the purpose and mission of Customer Service?

A. Customer Service is the first point of contact for customers, providing flexible options for contacting PGE via the phone, web, customer correspondence, and the Interactive Voice Response (IVR) phone system. Our mission is to deliver consistently high levels of service that result in satisfied customers while effectively managing our costs.

Q. What are PGE's goals for Customer Service?

A. PGE's primary goals for Customer Service include:

- Increasing the value customers receive from PGE and ensuring that programs and service options are customer-driven; and,
- Ensuring operational excellence to provide customer service at a reasonable cost.

Q. How does PGE measure whether these goals are being met?

A. PGE uses a number of tools and metrics to determine whether customer service goals are being met, including:

- Customer feedback received and reviewed by our Customer Relations team;
- Customer satisfaction ratings of each customer segment, where our goal is to be in the top quartile among our peer utilities and all utilities nationally;

- In July of 2007, PGE contracted with a third party to implement a customer satisfaction survey to ensure we were listening to the "voice of the customer." Customers calling our Contact Center are provided the opportunity to take a survey to ensure the above goal is met. We also emphasize first call resolution as a priority for our Customer Service Representatives. At the end of December 2007, approximately 94% of the customers surveyed indicated they were treated as a valued customer, and approximately 81% indicated they received first call resolution.[1]
- Tracking the number of at-fault complaints we receive. PGE received a total of 13 at-fault complaints in 2007. Our goal is to keep this number at a minimum, but not to exceed the OPUC service quality metric of 56 company-wide for 2007.
- Maintaining 85% accessibility and answer calls within 220 seconds measured from the point when the IVR routes customers into a specific customer service call queue (e.g., residential, business, or outage).
- Maintaining our 24-hour turnaround time in processing emails received through our portlandgeneral.com and .biz sites.
- Providing valuable programs and service options driven by customer needs. Examples include promoting paperless bills and renewable options when customers start or transfer service, and implementing a consolidated bill program for large customers.

Q. Please summarize Customer Service O&M costs from 2007 to the 2009 test year forecast.

1 The percent of customers rating the service provided with either an "8" or "9," with "9" being most satisfied. The rating for first call resolution is reflected as an average or "mean" score.

A. As Table 1 below summarizes, Customer Service expenses are increasing from approximately $66 million to approximately $73.7 million, and Customer Service full time equivalent (FTE) employees are increasing from approximately 595 to approximately 621.

Table 1
Customer Service Expenses ($Million) and Employees

	2007 Forecast [2]	2008 Budget	2009 Test Year
O&M Expenses	$66.0	$68.5	$73.7
FTEs	595	611	621

Q. What primary drivers increase the costs in Customer Service O&M?

A. There are four primary drivers of cost increases, these drivers are shown below in Table 2.

Table 2
Customer Service O&M Drivers of Cost Changes
from 2007 to 2009 Test Year Forecast

Cost Driver	($Million)
Wage Escalation and FTE Growth	$3.2
Write-offs of Uncollectible Accounts	2.0
Information Technology	1.2
Other Programs and Service Options	0.9
Total of Cost Drivers from 2007 to 2009	**$7.3**

Q. How is your testimony organized?

A. My testimony follows the order of Table 2 above. First, I discuss wage escalation and FTE growth. Next, I discuss the change in write-offs of uncollectible accounts. Then, I discuss costs in Information Technology (IT). Finally, I discuss Other Programs and Service Options and what is driving increased costs in that area.

2 The 2007 forecast represents nine months of actuals and three months of budget.

II. Wage Escalation and FTE Growth

Q. As shown in Table 2 above, the largest component of cost increases in Customer Service O&M from 2007 to the 2009 test year are wage escalation and growth in FTEs. Please describe how wage escalation increases costs between 2007 and 2009.

A. Wage escalation is discussed in Exhibit 800, Compensation and Benefits. Basically, it is the amount that PGE needs to increase wages in order to attract and retain quality employees. This accounts for approximately 30%, or $2.4 million of the total customer service O&M increase and 75% of the increase in the wage and FTE category.

Q. Please describe the second largest component, FTE growth.

A. FTEs increase by 24 in Customer Accounts and by two in Customer Service. The reason for this increase is customer growth. We staff FTEs to keep pace with customer growth and to maintain the workload and our high level of customer service. From 2005 to 2007, PGE's average number of customers and actual FTEs supporting these customers both increased approximately 1.6% annually, on average. This includes productivity improvements over these years in addition to new programs and services to meet customer expectations.

Q. Do the changes in wage escalation and FTEs include advanced metering infrastructure (AMI)?

A. No. The dollar and personnel impacts associated with AMI are accounted for in its own separate proceeding, UE 189.

III. Write-offs of Uncollectible Accounts

Q. PGE identifies write-offs of uncollectible accounts (uncollectibles) as another driver of increased costs. How does PGE minimize write-offs of uncollectible accounts?

A. PGE minimizes write-offs of uncollectible accounts by:

- actively pursuing fraud, ID theft, and energy theft;
- reaching out to past due active customers using different channels; for example making automated outbound calls, direct inserts and letters;
- increasing our field collections presence to follow up with more customers who are delinquent; and
- keeping abreast of best practices within the utility industry and incorporating appropriate practices with PGE.

Q. What components drive the amount of uncollectible accounts?

A. Uncollectibles are a function of two components: 1) light and power revenue, and 2) other revenue. As discussed in Exhibit 200 Revenue Requirements, we budget these in accordance with OAR 860-038-0200(9)(b)(D). In UE 180, the Commission approved the rate for Uncollectibles of 0.53% of revenue.

Q. What rate is PGE using for the 2008 and 2009 forecasts?

A. PGE uses a rate of 0.48% for this period. The light and power component for 2008 and 2009 is 0.43%, which is an average of the last three years of actual activity. PGE also includes a rate that reflects other write-offs, such as insurance claims related write-offs and other miscellaneous write-offs, forecasted to be 0.05%, which is based on an average of the last three years of actual activity. The overall rate of 0.48% represents a decrease of 0.05% from the UE 180 rate of 0.53%.

IV. Other Factors

Q. What other factors are drivers of the changes in cost for Customer Service O&M?

A. There are two other factors that drive costs higher from 2007 to the 2009 test year: 1) IT, and 2) Other Programs and Service Options. Together these two areas contribute approximately $2.0 million of the cost increase.

A. Information Technology

Q. Please explain the increase of approximately $1.2 million in IT costs.

A. Approximately $350,000 represents annual maintenance for the new integrated technologies system at PGE's Customer Service center to be completed in 2008, which will replace our separate telephone, IVR, and other systems. The remaining $857,000 is due to corporate IT allocations, as discussed in PGE Exhibit 500, Section II, part H.

B. Other Programs and Service Options

Q. What areas encompass PGE's Other Programs and Service Options?

A. PGE's Other Programs and Service Options include among other areas Customer Research, the Renewable Power Program, Demand Response (DR) Programs, E-Manager, ESS Business Office, and Other Products and Customer Communications.

Q. Please explain the overall increase of approximately $851,000 related to Other Programs and Service Options.

A. The 2009 test year costs are primarily made up of increases in DR program requirements, increased costs for utility products and services, other miscellaneous programs and services and Customer Communications. These costs are explained in greater detail below.

Q. What is Demand Response?

A. DR is the reduction of electrical consumption at the customer level in response to high wholesale electricity prices, system resource capacity needs or system reliability events. Reduction of electricity usage is achieved through curtailment or self-generation. DR typically involves reduction during peak-load events.

Q. What are some of the DR programs PGE currently offers or is researching?

A. PGE currently offers Dispatchable Standby Generation (DSG) and is currently ramping up load curtailment capability for large and medium size customer classes. DSG uses customer-owned generators that are grid connected to supply capacity to the PGE system within 10–15 seconds. During a DSG event, PGE is able to call on customer-owned resources to meet system demand.

PGE also anticipates offering an optional Critical Peak Pricing (CPP) tariff as one of the system benefits potentially realizable through AMI deployment. CPP is a form of time-of-use (TOU) rates, characterized by the imposition of premium prices during limited predefined periods. Because of the premium pricing, some customers will voluntarily curtail electricity demand during peak periods. CPP rates have been used by other utilities to curtail electric demand during periods of low utility reserve margins and serious system emergencies.

Load Control is also being researched. Load Control is a form of firm demand side resource where control of customer premise equipment by the customer, third party provider, or utility is granted by the customer to provide capacity to the system during times of stress on the grid.

Q. Why are costs increasing approximately $324,000 from 2007 to 2009 in the DR program?

A. The table below shows major program categories.

Table 3
Demand Response Programs

PROGRAM	2007 Forecast	2008 Budget	2009 Test Year
DSG	$231,474	$183,984	$189,133
CPP	18,000	64,000	86,772
Load Control	9,305	46,000	306,671
TOTAL	**$258,779**	**$293,984**	**$582,576**

DSG non-labor costs have decreased due to the transfer of contract labor in 2007 to a new specialist position added in 2009. With the acknowledgement of the IRP, PGE is committed to developing an additional 82 MW of DSG capacity over the next five years. The increase in the number of DSG projects requires additional staff to manage and support the projects.

Critical Peak Pricing increased due to ramping up the experimental tariff that involves enrollment materials and initial evaluation.

In 2009, Load Control consists of managing the curtailment contracts for large customers and updating the DR Resource Assessment for IRP development. Load Control increased primarily due to contractor fees for verification and settlement of load reductions and consulting costs for the resource technical assessment update required by IRP guideline 4, OPUC Order No. 07-002 and correcting Order No. 07-047.

For the 2007 IRP, PGE provided only an updated assessment rather than a comprehensive technical assessment of demand side capacity reports. A new comprehensive study is required as technological advances and experience gained prior to the next IRP planning cycle will render the existing assessment out of date.

Q. Miscellaneous program costs increase approximately $320,000. Please explain.

A. These costs include new product promotions, including but not limited to distributed solar and increased promotion of energy efficiency (EE) in support of the IRP, including technical assessment studies for EE requirements required by IRP guideline 6, OPUC Order No. 07-002 and correcting Order No. 07- 047.

PGE will continue the EE studies in conjunction with the ETO to ensure a comprehensive technical assessment of EE for the state and subcontracting with the ETO's consultant, taking into account anticipated advances in technology.

PGE also includes specialized vendor service charge increases for the Energy Information Services option for nonresidential customers due to customer enrollment growth.

Q. Why are costs increasing approximately $77,000 from 2007 to 2009 for customer communications?

A. PGE currently uses hard copy mail to communicate with customers about everything from renewable power options to the BPA credit suspension. PGE has approximately 200,000 online customers who have become more demanding of dynamic web, broadband and outbound e-mail communications.

PGE will begin an expansion of outbound e-mail communications in 2008 and carry this project forward in 2009. This project will take advantage of the new start service scripting, which will ultimately build a directory of PGE customer e-mail addresses, and PGE will reduce hard copy brochure printing by expanding e-mail communications. PGE's investment will offer potential savings to other parts of the company by boosting the volume of web transactions, reducing postage costs and reducing call volumes. Expanding web communications will require day-to-day updating of website topics such as EE solutions, rate changes, renewables, AMI, and future energy supply issues.

Q. What role do PGE-initiated communications play in the effective delivery of services?

A. These communications provide essential information regarding safety, wise and efficient use of energy, power options, billing and payment options, and general customer services options.

Q. Does PGE plan to reduce any costs through an Errata filing?

A. Yes. PGE will remove $160,000 from the 2009 test year forecast through an errata filing for nonutility program expenses that were inadvertently included in Other Programs and Service Options.

Q. Does this conclude your testimony?

A. Yes.

UE ___ / PGE / 800
BARNETT - BELL

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Total Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Arleen Barnett
Joyce Bell

February 27, 2008

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I. Introduction

Q. Please state your name and positions with PGE.

A. My name is Arleen Barnett. My position is Vice President, Administration. My responsibilities include establishing compensation policy and employee policies, improving the work environment, overseeing employee relations, managing employee development, and overseeing Business Continuity and Security. My responsibilities also include oversight for PGE’s Information Technology Department. My qualifications are provided at the end of this testimony.

My name is Joyce Bell. My position is Director of Compensation and Benefits in the Human Resources Department. My qualifications are also provided at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony presents and explains PGE's compensation costs for the 2009 test year and describes significant changes since 2007. Total compensation costs include base wages and salaries, incentive pay, and employee benefits. We forecast our total compensation costs based on the markets within which we must compete to acquire and retain employees. We describe PGE’s employee incentive and benefits costs and show how these programs are reasonably designed and competitively priced.

Q. What are PGE’s expected costs for total compensation in 2009?

A. PGE forecasts total compensation costs for 2009 to be approximately $289.8 million. This represents a 4.88% annual increase since 2007. Table 1 summarizes the costs of these components. PGE Exhibit 801 provides additional detail.

Table 1
Estimated Total Compensation Costs ($000)

Component	2007 Forecast	2008 Budget	2009 Test Year
Wages & Salaries	194,810	210,404	222,519
Incentives	18,720	14,178	14,773
Benefits	49,904	48,923	52,505
Total Compensation	**263,434**	**273,506**	**289,797**

The total increase in wages and salaries since 2007 is primarily due to market-driven wage and salary adjustments and FTE growth (approximately $13.9 and $13.8 million; see PGE Exhibit 802). Test year incentive costs are significantly less than the 2007 forecast. Benefits reflect continued cost increases, particularly for health and dental care programs.

Q. What is PGE's total compensation philosophy?

A. PGE's philosophy is to provide compensation sufficient to attract and retain employees necessary to provide safe and reliable electric service at a reasonable price with outstanding customer service. At the same time, PGE actively controls costs by targeting our compensation program attributes and costs to reflect market median conditions. As market practices change, PGE responds to ensure that our total compensation package is competitive and generally tracks the market.

Q. What major challenges does PGE face in following its compensation philosophy?

A. PGE faces three major challenges: 1) recruiting, 2) rising health care costs, and 3) an experienced but aging workforce. The third challenge compounds the difficulty of managing the first two.

Q. Please describe PGE's approach to the first challenge – recruiting.

A. PGE faces a significant challenge in recruiting and hiring that is common to the industry. In particular, PGE has experienced difficulty in filling five categories of positions:

- Skilled trades, such as Linemen, Wiremen, Metermen, and Instrumentation and Control Technicians;

- Transmission Engineering;
- Civil Engineering;
- Information Technology (IT) positions; and
- Finance positions (particularly in the tax area).

To fill these positions, PGE has increased its targeted recruitment and outreach activity. For example, PGE is now using specialized search firms to recruit applicants to fill IT and Finance positions. For skilled trade positions, what was once a local or regional search is now a national search. Some companies compete for this talent by offering signing bonuses and relocation packages, but PGE generally has not yet needed to use these high-cost options for skilled trade positions. PGE fills some journeyman positions through apprenticeship training, but the current wait-time for a lineman apprenticeship at PGE is approximately 18 months (down from eight years in the late 1990s). We are also investing in outreach activity, for example, working with the Oregon Building Congress by supporting the Academy for Architecture, Construction & Engineering, a charter school that prepares high school juniors and seniors for careers within the professional technical arena.

Q. What strategy does PGE utilize to meet the second challenge – rising health care costs?

A. PGE performs internal studies to understand which health issues are adding the most costs. PGE has developed targeted wellness programs to reduce long-term costs by lowering employee risk factors. PGE also aggressively negotiates with vendors for favorable terms for provider contracts. Finally, when health plan costs do rise, employees share the increased burden, aligning their interests with PGE's interests in keeping costs down.

As mentioned in PGE Exhibit 100 - Policy, PGE participates in the public forum regarding health care overhaul in our state. The Oregon Business Plan recommends:

1) value-based purchasing strategies, 2) health information technology and infrastructure, and 3) planning to improve access to health care. As is appropriate and possible for PGE, our benefits negotiations also include components of these recommendations.

Q. Please describe how PGE is planning to meet the third challenge – an aging workforce.

A. We expect that the annual number of retirees will continue to climb as approximately one-third of PGE's workforce will become eligible for retirement (at least 55 years of age and five years of service) by the end of 2009. For power generation employees, the demographic challenge is more pressing: 52% of non-bargaining and 41% of bargaining power generation employees are currently eligible for retirement. PGE will recruit and train employees to fill vacancies anticipated from retiring employees and we are exploring ways to use experienced employees to train new employees before they retire. We expect that, in the future, additional FTEs will be necessary to cross-train in particular positions with our highly experienced personnel. Finally, PGE is placing increased emphasis on health and wellness programs that should lower medical costs by reducing some health risk factors that are common to an aging workforce.

II. FTEs and Wages & Salaries

Q. How does PGE calculate its 2009 total wage and salary revenue requirement?

A. Wages and salaries are a function of the number of full-time equivalents (FTEs) and pay structure.

Q. Please describe how PGE determines the number of FTEs required for the test year.

A. As part of each annual budgeting process, managers determine the number of labor hours in each position type required to accomplish their departments' work. PGE groups position types into 17 categories for exempt employees (excluding officers), 14 categories for non-exempt employees, and 1 category for union employees. PGE then converts the total labor hours into FTEs. For example, under this process, an employee hired mid-year would be budgeted as one-half (or 0.5) FTE. Table 2 provides PGE's total full-time equivalents for 2007 through 2009.

Table 2
Full-Time Equivalents

PGE FTEs (straight time, unless indicated)	**2007 Forecast**	**2008 Budget**	**2009 Test Year**
Administrative and General	639	656	665
Customer Accounts	510	526	535
Customer Service	75	76	81
Generation	393	417	434
Transmission & Distribution	962	1,003	1,007
Trojan Decommissioning	14	13	12
Overtime (includes all categories)	103	92	93
Total FTEs	**2,697**	**2,784**	**2,827**

Q. Why do FTEs increase from 2007 to 2009?

A. FTE increases between 2007 and 2009 are primarily due to four factors: additional regulatory requirements, new generating plants, growth in our customer base, and efforts to reduce overtime. First, costs are steadily increasing as compliance with new regulatory requirements demands more resources. Second, PGE has staffed two new power plants (Port Westward and Biglow 1). Third, PGE has increased its FTEs for distribution functions, to help manage an expected number of customer contacts and to provide enhanced customer services. Finally, PGE's 2008 budget and the test year forecast include FTE increases to reduce the amount of overtime and to enable the transition due to retirements.

Q. Please describe how PGE determines its pay structure.

A. In keeping with PGE's total compensation philosophy, PGE routinely compares its wages and salaries to the relevant markets. This practice ensures that our current and prospective employees are fairly compensated while costs are controlled. In 2007, we compared 19 hourly non-union and 57 salaried non-officer positions with the market. The study showed that PGE's wage and salary structure is highly correlated with the market and that the correlation has increased since 2005.

PGE reviews market surveys and Bureau of Labor statistics and also considers employee merit changes to estimate the wage escalation factor used to develop the 2009 test year. PGE forecasts a 4.5% annual increase in non-bargaining wages and salaries. We forecast 2009 bargaining employee escalation to be in line with the non-bargaining forecast. Combining required FTEs with wage and salary guides determines PGE's 2009 test year revenue requirement. Table 3 summarizes total wage and salary costs for 2007 through 2009.

Table 3
Total Wages & Salaries ($000)

PGE Wages & Salaries (straight time, unless indicated)	**2007 Forecast**	**2008 Budget**	**2009 Test Year**
Administrative and General	$50,693	$55,400	$58,505
Customer Accounts	25,239	27,226	28,883
Customer Service	6,352	6,731	7,329
Generation	30,283	33,828	36,500
Transmission & Distribution	68,163	74,326	77,585
Trojan Decommissioning	1,035	899	808
Overtime (includes all categories)	13,045	11,994	12,909
Total Wages & Salaries	**$194,810**	**$210,404**	**$222,519**

Q. What are the problems with the convention that the Commission Staff has used in the past to calculate wage and salary costs?

A. The Commission Staff has used a "three-year wage model" to estimate allowed wage and salary increases. The calculation adjusts for work-force increases and then applies three years of Consumer Price Index (CPI) growth to employees' average base salaries. However, Staff's three-year model does not consider how businesses actually make decisions about employee compensation and can overestimate or underestimate the cash compensation necessary for PGE to compete in the market. In essence, the three-year wage model assumes that wage and salary escalation tracks general price inflation and that cash compensation is unaffected by benefit program changes, incentive pay, and merit increases. These are incorrect assumptions.

Q. Why is it reasonable to base compensation costs on labor market data instead of an inflation-based three-year wage model?

A. PGE's wages or salary structure reflects market data and accounts for specific skills and experience. For example, wage escalation generally exceeds price inflation in tight labor markets, as market demand drives labor prices upward. PGE currently competes in an extremely tight labor market for skilled trades employees, so we would expect to pay higher wages to those employees than a CPI-based three-year model would forecast.

III. Incentives

Q. What is PGE's strategy for incentive compensation?

A. As with wages and salaries, PGE's strategy is to provide incentive levels that attract, retain, and motivate employees. PGE monitors the employment market and acquires information regarding incentive compensation program design practices. Even though it is just a fraction of PGE's total compensation, incentive compensation allows PGE to remain competitive in the labor market while encouraging employee performance and productivity. PGE's incentive programs align compensation costs with shared customer and company goals to reduce power costs, improve customer satisfaction, and preserve PGE's financial stability.

Q. What fraction of PGE's total compensation are incentives?

A. Incentive compensation comprises 7.1% of PGE's 2007 total compensation, but only 5.1% of the 2009 total. Incentives in 2007 were not normal because of significant items that relate to prior periods and favorable results related to 2007 power costs, compounded by the effects of SB 408. PGE forecasts that incentive costs will decrease approximately 21.1% from 2007 to 2009 because the test year forecast is based on normal results. Table 4 provides our detailed forecast for 2007 through 2009.

Table 4
Total Incentives ($000)

Incentives Component	**2007 Forecast**	**2008 Budget**	**2009 Test Year Forecast**
Corporate Incentive Program	$7,226	$5,706	$6,552
Annual Cash Incentive	8,367	5,035	5,181
Stock (long-term incentive plan)	2,449	3,211	2,813
Notables and Miscellaneous	678	227	227
Total Incentives	**$18,720**	**$14,178**	**$14,773**

Q. How do PGE's cash incentive compensation programs align employee performance measures with customer interests?

A. PGE aligned its cash incentive compensation programs, the Corporate Incentive Program (CIP) and the Annual Cash Incentive (ACI), with customer interests by funding the incentive pool based on PGE's success in achieving four customer-focused goals:

- Overall Customer Satisfaction: This goal consists of 1) the average quarterly percent rating of the Market Strategies International ("MSI") study for residential customers, 2) the average semi-annual percent rating of the MSI study for business customers, and 3) the annual results from the TQS Research, Inc. National Utility Benchmark of Service to Large Key Accounts.
- Power Distribution Quality and Reliability: This is measured by comparing the actual System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Event Frequency Index (MAIFI) scores. Our initial targets are set at 85, 1.10, and 4, respectively.
- Generation Plant Availability: Plant availability generally influences power costs. In the long-term, as we reduce forced outage rates, power costs should also be lower.
- Financial strength: Proven financial strength can reduce customer rates through lower borrowing costs, resulting in a lower cost of capital. PGE targets 100% of budgeted net income.

PGE's ability to meet these goals will determine the incentive pool for CIP participants and non-officer and officer ACI participants. Actual award amounts (an employee's portion of the incentive pool) for non-officers (CIP and ACI) will be based on employees' incentive targets and their performance achieving Scorecard results. Actual officer ACI costs will be based entirely on the four customer-focused goals.

Q. What changes has PGE made in the CIP structure since 2007?

A. PGE has made changes to more closely align cash incentives for EX-13 employees with the market. The short-term cash incentive target for all employees in the CIP was previously set at 6.25% of base pay. According to a 2006 Towers Energy Services Survey (Towers), the target fell below the benchmark for employees classified as exempt level nine and above. Due to PGE's labor situation and the growing importance of employee retention, PGE began the process of adjusting the CIP target to align more closely with the market by creating a new program: "CIP-13".

CIP-13 was introduced in 2008 for non-bargaining employees who are classified as exempt level 13 who are not participating in another short-term annual cash incentive program. As with CIP in general, the CIP-13 performance measures are based on goals that 'stretch' the employee, reflected on employee and department Scorecards. Towers indicates that companies provide a target incentive of 14% of base pay for employees in this category. The CIP-13 program more closely matches market practice by setting the target cash incentive at 10.8% of base pay. PGE may make future adjustments for other exempt employee levels, but they are not yet finalized and are not included in the test year.

Q. Please describe PGE's long-term incentive program.

A. PGE initiated its stock incentive plan in 2006 and it reflects market practice; many publicly traded companies provide stock incentives to promote performance and retention of directors, officers, and key employees. PGE's stock incentive awards are earned and paid out over several years. The Commission approved this stock issuance and accurately summarized the goals of the plan: "The Plan is part of the Company's overall compensation package and is intended to provide incentives to attract, retain, and motivate officers, directors, and key employees of the Company" (Order No. 06-356, p.1). PGE forecasts approximately $2.81 million for the 2009 total stock incentive expense.

Q. Does PGE have any other programs that reward employees' performance?

A. Yes. Notable Achievement Awards (Notables) and Miscellaneous Awards are given to employees on a case-by-case basis. Notables are distributed to recognize employees' outstanding work on a specific project or task. PGE's 2009 forecast for Notables is $200,000 ($114,000 less than 2007). PGE forecasts $27,000 for miscellaneous awards that are also available on a case-by-case basis, but do not fit within the Notable framework.

At times, and in specific situations, we have also employed other types of incentives, such as signing bonuses and retention payments, in periods of critical skill competition or to ensure the completion of important tasks. However, these types of incentives are not included in the 2009 test year incentive forecast.

IV. Benefits

Q. What is PGE's benefit compensation strategy?

A. PGE strives to maintain a benefits portfolio that balances benefit features and costs between programs, between employee groups, and between PGE and the market. As with wages/salaries and incentives, PGE compares our benefits programs to the market and targets prevailing market attributes. As a result, our portfolio is sufficient to attract and retain quality employees. PGE also uses market information to create innovative program designs to provide greater employee choice and improve our ability to control costs.

Q. What components comprise PGE's total benefits?

A. Health and Welfare, post-retirement, disability and life insurance, and miscellaneous benefits encompass PGE's total benefits. Because of our efforts to control costs, PGE's total benefits costs are expected to increase only 2.6% annually from 2007. We project 2009 employee benefit costs of $52.5 million.

Table 5
Total Benefits ($000)

Benefits Compensation Component	2007 Forecast	2008 Budget	2009 Test Year Forecast
Health and Wellness	$28,134	$29,040	$32,016
Disability and Life Insurance	3,040	2,626	2,821
Post-Retirement Accrual	17,437	16,043	16,187
Miscellaneous Benefits	796	873	1,054
Benefits Administration	497	341	427
Total Benefits	**$49,904**	**$48,923**	**$52,505**

Benefits comprise the second-largest component of total compensation; hence, managing these costs is important.

Q. How is PGE trying to mitigate increases in benefits costs?

A. As stated previously, PGE works hard to keep benefits costs down through programs that encourage a healthy workforce, modifying benefits plan structures to track market practice, and negotiating for favorable contract terms. PGE also reduced health care costs by bringing Coyote Springs and Port Westward bargaining employees into the flex-dollar benefits program structure. Additionally, when health care premiums do rise, PGE shares the cost increases with employees.

PGE also adjusts program features to help control costs. For example, PGE converted the Sick Benefit Policy for exempt employees to a Short-term Disability Plan. The short-term disability benefit can only be used for time off for one's own illness or injury, and not to pay for other types of leaves, thus eliminating the potential for significant future cost increases. PGE initiated an Integrated Absence Management (IAM) system in late 2007 to centralize absence tracking and help reduce employees' return-to-work time. These programmatic changes should reduce future years' sick benefit costs and improve employee productivity.

Finally, PGE invests in internal health and wellness programs to help lower health "risk factors" that should reduce long-term medical issues and reduce plan costs. We provide tools for persons identified as high risk during health screenings to lower their medical risks. PGE's medical vendors also provide wellness programs and disease management programs for our employees.

Q. What drives the increase in PGE's Health and Wellness benefits costs?

A. The main drivers are Health and Dental Plan premium increases. In 2007, for non-union employees, Kaiser medical premiums increased 9.9% and Providence premiums increased between 2.0% and 5.5%. For 2008, Kaiser premiums increased 10.4% and Providence premiums will increase between 6.5% and 12.3%. Health care premiums for the main bargaining unit are a negotiated benefit and managed by the Taft Hartley Trust. We forecast bargaining employee health and dental plan costs will increase approximately 10% annually.

Health and Dental Plan increases are partially offset by a decrease in union retiree medical costs. The 2009 test year revenue requirement anticipates that an enhanced union post-retirement benefit, provided in the most recent main bargaining unit contract, will not be renewed.

Q. How do PGE's health plan costs compare to market benchmarks?

A. PGE's health plan costs are very close to market benchmarks. The 2007 Towers Perrin Health Care 360 Performance Study found that, overall, PGE has lower health plan costs than the energy/utilities industry benchmark. PGE's non-union health care program (normalized for age/gender demographics, family size, geography, and plan value) is 13% more efficient than the database benchmark while the union program is very close to the normalized benchmark (3% higher).

Also, Hewitt and Associates reviewed PGE's employer contribution percentage to Health and Dental costs. The analysis showed that the employer contribution at market was 84%. Because PGE closely matched market practice, we made no change to program structure and estimate that company contributions will be 85% of the weighted average of program premiums.

Q. What other Health and Wellness expenses are included in the 2009 test year?

A. PGE forecasts $462,000 in other Health and Wellness costs in the 2009 test year. These costs are for programs that encourage healthy lifestyle decisions. For example, PGE launched the Energy for Life website in 2006 to help manage PGE's demographic challenges and promote a healthy and productive workforce.

Q. Please explain PGE's 2009 disability and life insurance benefit forecast of $2.8 million.

A. PGE's disability and life insurance benefits are comprised of union short-term disability insurance, long-term disability insurance, and group life insurance.

PGE forecasts union short-term disability insurance costs to be approximately $634,000 in the test year. PGE successfully negotiated a competitive union short-term disability contract that renews annually. For the main bargaining unit, PGE is obligated to provide coverage through February 28, 2009. Costs for 2008 and 2009 appropriately reflect current claims history. PGE's non-union short-term disability expense is included as a payroll labor loading, and is not included in the short-term disability forecast. PGE forecasts long-term disability costs to be approximately $1.36 million in 2009. PGE pays 85% of the health care benefits for employees on long-term disability.

PGE forecasts group life insurance costs to be approximately $828,000 in 2009. Actuarial assumptions for mortality rates were changed in 2007, reflecting longer expected life-spans. This change results in reduced annual contributions because investments have more years to accrue earnings. For bargaining employees, PGE pays for retiree members' life insurance. Active union members pay for their own life insurance.

Q. What is included in PGE's Post-Retirement benefits costs?

A. PGE classifies the Retirement Savings Plan (RSP) and the PGE Pension Plan as post-retirement benefits. For purposes of this testimony, we also present the Health Reimbursement Account (HRA) as a post-retirement benefit[1]. Post-retirement benefits help support employee recruitment and are important because we want to retain

[1] To comply with ERISA accounting guidelines, PGE classifies the HRA as a health and wellness benefit, even though employees do not receive the benefit until after retiring from PGE.

retirement-eligible employees while we prepare to transition their responsibilities to other employees.

PGE's RSP costs are based on employee contributions and PGE's match and include an employer contribution for union employees not in the defined benefit plan. These costs change with base wage and salary levels and employee participation. Employees represented under the main bargaining contract participate in PGE's pension program or the RSP, as discussed in PGE's UE 180 filing. From 2007 to 2009, program costs are expected to increase from $13.6 million to $14.7 million, or 3.7% annually.

PGE requests no pension benefit cost in this proceeding because future benefit obligations are less than the expected value of the assets currently held in the plan. As in previous rate cases, we exclude a negative net periodic pension cost from the test year revenue requirement. According to the Employee Retirement Income Security Act of 1974 (ERISA), PGE cannot use these plan assets for any purpose other than funding retirement benefits, as long as the plan is in operation. Therefore, regulatory orders commonly restrict pension plan assets from offsetting operational costs.

PGE forecasts total HRA costs to be approximately $1.5 million in 2009. The HRA provides a post-retirement benefit to cover a portion of health care premiums for employees who retire from PGE. For non-bargaining employees, only those who retire from PGE will receive any HRA benefit. For non-bargaining employees, PGE places one-half of 1% of wages and salaries into a notional account for retiree HRA benefits. The current main bargaining contract provides that, beginning July 1, 2008, PGE will contribute 50 cents per straight-time hour into the HRA account and that bargaining employees have a notional account for sick leave (as of the end of April 2004).

Q. What is PGE's 2009 cost for miscellaneous employee benefits?

A. PGE forecasts 2009 costs for miscellaneous benefits to be $1.05 million. Miscellaneous benefits are additional tools to attract and retain employees. They help balance employer-provided benefits with changing realities of our demographics and market position. The majority of PGE's miscellaneous benefits costs are for educational assistance, the Service Awards program, Colstrip benefits costs, and partial health club reimbursements.

- Education Assistance ($485,000) – We assume no change in the level of program participation but forecast a slight dollar change because we expect tuitions to increase.
- Service Awards ($225,000) – As a retention strategy, PGE honors employees for their years of service at five-year anniversary intervals.
- Colstrip Benefits ($139,000) – PGE co-owns the Colstrip 3 & 4 generation plants and is "charged-back" a lump sum for health care premiums and other benefits for PGE's share. The 2009 forecast reflects an increase in these benefits costs.
- Health Club Partial Reimbursement ($100,000) – Employees become eligible for a $15 monthly reimbursement only if they meet health club attendance requirements. This program supports our Energy for Life program.

Q. Why do PGE's Benefits Administration costs decrease from $497,000 in 2007 to $427,000 in 2009?

A. PGE hired consultants to help us prepare and issue two "request-for-proposals" to select administrators for the new Employee Stock Purchase Plan and the Stock Incentive Program. Once the administrators are chosen, we expect that the consultant expense will decrease.

V. Summary and Qualifications

Q. Please summarize your testimony.

A. PGE must provide a total compensation package sufficient to attract, retain, and encourage performance beneficial to PGE and our customers. Thus, PGE designs its total compensation program with reference to the labor markets in which we compete. This approach provides a total compensation structure, comprised of wages and salaries, incentives, and benefits, that is competitive, and cost effective.

Q. Ms. Barnett, please summarize your qualifications.

A. I received a Bachelor of Arts degree from Abilene Christian University in 1972 and certification in Human Resources at Portland State University. I have completed coursework toward an MBA in Human Resources at the University of Portland. As Vice President of Administration, I oversee Business Continuity and Security, Information Technology, and Human Resources areas.

I joined PGE in 1978 and have successfully bid and been selected for various positions at PGE. I guided the HR department through the merger with Enron in 1997 and became Vice President in 1998. My scope was broadened to include Information Technology in 2002.

Q. Ms. Bell, please summarize your qualifications.

A. I received a Bachelor of Arts degree from the University of Pittsburgh in 1975. I received a Masters in Business Administration from the Joseph M. Katz Graduate School of Business, University of Pittsburgh, in 1976. Prior to joining PGE, I worked at Fireman’s Fund Insurance, Co. and American Express in finance; and at Baltimore Gas & Electric Company in the areas of finance and human resources. In 1988, I joined Portland General Electric and I have been Director of Compensation and Benefits since 1998.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
801	Summary of Compensation Cost
802	Wages and Salaries, Separated for Escalation and New FTE

SUMMARY OF COMPENSATION COST ($000)

Compensation category / program		2005 Actual	2006 Actual	2007 Forecast	2008 FOM	2009 Rate Cs
Benefit Compensation						
Health & Dental Plan		26,867	25,930	27,809	28,705	31,555
Employee Wellness Program		138	237	275	273	397
Health Reimbursement Account		1,203	1,454	1,615	1,815	1,531
Short Term Disability Insurance		227	314	404	476	634
Long Term Disability Benefits		1,487	(202)	1,505	1,355	1,358
Group Life Insurance		1,131	1,153	1,131	794	828
Employee Assistance Program		53	48	51	62	64
Retirement Savings Plan		14,593	12,224	13,620	14,228	14,656
Pension Plan	a	2	3,915	2,203	-	-
Education Plan		459	495	464	453	485
Recreation Program		23	19	13	25	26
Misc. Employee Benefits		191	163	319	395	544
Benefits Administration		347	409	497	341	427
Supp. Exec. Pension (SERP)	b	-	-	-	-	-
MDCP Pens/Savings Makeup	b	-	-	-	-	-
Benefit Compensation Total		46,722	46,158	49,904	48,923	52,505
Wages & Salaries						
Regular Utility (CE11, CE12)		164,989	172,818	181,765	198,410	209,610
Overtime Utility (CE16, CE17)		11,751	15,598	13,045	11,994	12,909
Wages & Salaries Total		176,741	188,416	194,810	210,404	222,519
Incentive Compensation						
Boardman Tmwrks (PGE share)		98	53	127	108	108
Coyote Springs (PGE Share)		193	286	141	168	174
Port Westward		-	-	349	277	285
Pelton CIP (PGE Share)		2	2	2	2	2
Trojan (PGE share of PGE O&M)		-	-	-	-	-
PGE CIP		3,563	3,720	6,606	5,150	5,983
Boardman ACI (PGE share)		55	36	69	60	60
Pelton ACI		21	54	(9)	17	17
Wholesale Marketing		588	751	1,583	906	933
PGE ACI		1,741	2,236	2,464	2,365	2,434
Officer ACI		1,357	1,087	4,260	1,686	1,737
Stock Incentive Plan		-	717	2,449	3,211	2,813
Notable Achievement Awards		193	256	314	200	200
Retention/Signing Awards		37	-	-	-	-
Miscellaneous Awards		-	-	365	27	27
Total Incentives		7,847	9,199	18,720	14,178	14,773
Total Compensation		**231,310**	**243,774**	**263,435**	**273,506**	**289,797**

a credits set to zero
b omitted from revenue requirement

Total Compensation Component	2005 Actual	2006 Actual	2007 Forecast	2008 Budget	2009 Test Year	07 - 09 Ann. Growth	Two-Year % Change
Wages and Salaries	176,741	188,416	194,810	210,404	222,519	6.9%	14.2%
Incentives	7,847	9,199	18,720	14,178	14,773	-11.2%	-21.1%
Benefits	46,722	46,158	49,904	48,923	52,505	2.6%	5.2%
Total Compensation	**231,310**	**243,774**	**263,435**	**273,506**	**289,797**	**4.9%**	**10.0%**

Wages and Salaries Component	2005 Actual	2006 Actual	2007 Forecast	2008 Budget	2009 Test Year	07 - 09 Ann. Growth	Two-Year % Change
Regular Time	164,989	172,818	181,765	198,410	209,610	7.4%	15.3%
Over Time	11,751	15,598	13,045	11,994	12,909	-0.5%	-1.0%
Total Wages and Salaries	**176,741**	**188,416**	**194,810**	**210,404**	**222,519**	**6.9%**	**14.2%**

Incentives Component	2005 Actual	2006 Actual	2007 Forecast	2008 Budget	2009 Test Year	07 - 09 Ann. Growth	Two-Year % Change
CIP	3,855	4,062	7,226	5,706	6,552	-4.8%	-9.3%
ACI	3,761	4,165	8,367	5,035	5,181	-21.3%	-38.1%
Stock	0	717	2,449	3,211	2,813	7.2%	14.8%
Notables and Miscellaneous	230	256	678	227	227	-42.2%	-66.5%
Total Incentive	**7,847**	**9,199**	**18,720**	**14,178**	**14,773**	**-11.2%**	**-21.1%**

Benefits Component	2005 Actual	2006 Actual	2007 Forecast	2008 Budget	2009 Test Year	07 - 09 Ann. Growth	Two-Year % Change
Health & Dental Plan	26,867	25,930	27,809	28,705	31,555	6.5%	13.5%
Employee Wellness Program	138	237	275	273	397	20.3%	44.6%
Employee Assistance Program	53	48	51	62	64	12.7%	26.9%
Short Term Disability Insurance	227	314	404	476	634	25.3%	56.9%
Long Term Disability Benefits	1,487	-202	1,505	1,355	1,358	-5.0%	-9.7%
Group Life Insurance	1,131	1,153	1,131	794	828	-14.4%	-26.7%
Health Reimbursement Account	1,203	1,454	1,615	1,815	1,531	-2.6%	-5.2%
Retirement Savings Plan	14,593	12,224	13,620	14,228	14,656	3.7%	7.6%
Pension Plan	2	3,915	2,203	0	0	-100.0%	-100.0%
Education Plan	459	495	464	453	485	2.3%	4.6%
Recreation Program	23	19	13	25	26	40.3%	96.9%
Misc. Employee Benefits	191	163	319	395	544	30.5%	70.2%
Benefits Administration	347	409	497	341	427	-7.3%	-14.1%
Total Benefits	**46,722**	**46,158**	**49,904**	**48,923**	**52,505**	**2.6%**	**5.2%**

Benefits Group	2005 Actual	2006 Actual	2007 Forecast	2008 Budget	2009 Test Year	07 - 09 Ann. Growth	Two-Year % Change
Health and Wellness	27,058	26,214	28,134	29,040	32,016	6.7%	13.8%
Disability and Life Insurance	2,846	1,265	3,040	2,626	2,821	-3.7%	-7.2%
Post-Retirement	15,798	17,593	17,437	16,043	16,187	-3.6%	-7.2%
Miscellaneous Benefits	673	677	796	873	1,054	15.1%	32.4%
Benefits Administration	347	409	497	341	427	-7.3%	-14.1%
Total Benefits	46,722	46,158	49,904	48,923	52,505	**2.6%**	**5.2%**

% of Total Compensation	2005	2006	2007	2008	2009
Wages	76.4%	77.3%	74.0%	76.9%	76.8%
Incentives	3.4%	3.8%	7.1%	5.2%	5.1%
Benefits	20.2%	18.9%	18.9%	17.9%	18.1%

G:\RATECASE\OPUC\DOCKETS\2009 Test Year\Testimony_PGE\Direct\Exhibit 800_Compensation\Exhibits\[Exhibit 801 - Summary of Comp Costs.xls]Summary of Benefit Costs

Notes:

1 **2008 data from January 2, 2008 FOM run.**
2 **2009 data from January 4, 2008 FOM run.**
3 Only contains M, N, X, Y ledgers and balance sheet data.
4 Entities 94x and 95x are excluded (941, 942, 951, 952, 953, 954)
5 **RC 929 (AMI project office) excluded from 2008 and 2009 FOM data.**
6 All entries are PGE share
7 2009 RC 013 does not have power costs.
8 2007 Forecast is 9 months actuals plus 3 month budget.
9 **2008 Rate Case FOM from January 9, 2007.**
10 **General manager and VPs added to file.**
11 **Variance columns now show 2007 forecast vs 2009 FOM and 2008 FOM vs 2009 FOM**
13 **Only CE 11, 12, 16, 17 (labor only)**

Utlity NonUtility	FERC	INCOME STMT	2007 FCST	2008 FOM	2007 to 2008 Escl	2009 FOM	2008 to 2009 Escl	2007 FCST VS 2009 FOM	2008 FOM VS 2009 FOM	Escalate Summ
Approximate total from Escalation File, Utility Only			195,798,029	211,077,055	6,053,752	223,222,115	9,214,995	26,901,213	11,622,187	15268746
Average escalation rate					2.87%		4.13%			
From Exhibit 801 ($000)			194,810	210,404		222,519				
Estimated W&S for 2007 FTE, escalated at average rate				200,397		208,670		13,860		
Estimated W&S not attributed to Escalation)						13,849				

G:\RATECASE\OPUC\DOCKETS\2009 Test Year\Testimony_PGE\Direct\Exhibit 800_Compensation\Exhibits\[Exhibit 802 - Wage and Salary Escalation.xls]File notes

UE ___ / PGE / 900
HAGER - STATHIS

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Patrick G. Hager
Kristin A. Stathis

February 27, 2008

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. I am responsible for analyzing PGE's cost of capital. My qualifications appear at the end of this testimony.

My name is Kristin A. Stathis. I am the Manager of Finance. I am responsible for cash management, corporate credit, managing PGE's pension and other related investments as well as corporate finance, including discussions with financial rating agencies regarding PGE's financial outlook and its funding requirements. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to recommend PGE's cost of capital for the 2009 test year. Our requested cost of capital and capital structure provides PGE the opportunity to earn a fair return while keeping its costs reasonable. As Dr. Zepp discusses in his testimony, PGE Exhibit 1000, guidance regarding cost of capital decisions are provided by the Bluefield and Hope Supreme Court decisions[1] as well as ORS 756.040.

Q. What are PGE's financial goals?

A. Our overall goal is to be viewed by the financial markets as a well-performing, vertically integrated utility. This would include:

- Maintaining investment grade bond ratings;
- Accessing financial markets to provide liquidity for operations and capital expenditures;

[1] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia* (262 U.S. 679 (1923)) and *Federal Power Commission v. Hope Natural Gas Co.* (320 U.S. 591 (1944)).

- Attracting capital on reasonable terms;
- Achieving an actual return on equity that is at or above that achieved by a group of utilities with similar characteristics, service territory and business risks; and,
- Setting prices at a sufficient level to recover prudently incurred costs, including an overall return on utility investment.

Q. You mentioned the importance of access to the financial markets. Why does PGE need to maintain access to these markets?

A. As noted above, PGE needs access to financial markets, including equity, debt and credit markets, to provide cash and liquidity for operations and its significant capital expenditures over the next few years. By maintaining a strong financial profile and financial flexibility, PGE expects to preserve its ability to raise capital at reasonable terms under various market conditions. Additionally, PGE needs access to the financial markets to actively manage its debt portfolio and credit arrangements to take advantage of opportunities to refinance or restructure when terms are favorable. Through diligent portfolio management, PGE has refinanced debt when prudent and has renegotiated credit arrangements which benefits customers by lowering the overall cost of debt.

Q. Was PGE been able to maintain access to financial markets during 2007?

A. Yes. PGE was able to issue $375 million in debt in 2007. PGE's solid, investment grade credit ratings and positive credit quality allowed PGE access to the financial markets, even in the volatile market of 2007, which was experiencing tighter lending standards.

Q. How will a positive outcome in this rate case impact PGE?

A. A positive outcome in PGE's rate case is important to maintain future access to financial markets. Regulatory support to recover prudent costs is essential to maintain a stable, high quality credit rating. As discussed above, good credit quality is critical to secure financing in volatile financial markets.

Q. What is your requested overall cost of capital for this filing?

A. We request and support an 8.66% cost of capital for the 2009 test year, including a 10.75% Required Return on Equity (RROE). This point estimate is for revenue requirement purposes and is based on a recommended range of 8.63% to 9.03% for PGE's cost of capital and a recommended range of 10.7% to 11.5% for PGE's RROE. Table 1 below shows the recommended cost of the two components of PGE's capital, common equity and debt. Table 1 also shows PGE's 2009 forecasted capital structure.

Q. How did you derive the overall recommended cost of capital?

A. We first estimated the cost for each component by considering the range, PGE's risks, and financing needs. We then determined the "weighted" cost by multiplying the component's cost by its weight (i.e., percent) in our recommended capital structure. Finally, we summarized the weighted cost of each component to derive the weighted or composite cost of capital. Table 1 summarizes these calculations.

Table 1
PGE's Weighted Cost of Capital
(Test Year 2009)

Component	Average Outstanding ($000)	Percent of Capital	Cost	Weighted Cost
Long-term Debt*	1,613,950	50.00%	6.57%	3.28%
Common Equity	1,520,838	50.00%	10.75%	5.38%
Total	**3,134,788**	**100.00%**		**8.66%**

* Long-term debt is calculated using the annualization method approved in Order No.07-015

Q. How is your testimony organized?

A. After this introduction, we discuss PGE's long-term debt, including new and redeemed issues and in Section III we discuss PGE's capital structure. In PGE Exhibit 1000, Dr. Zepp discusses PGE's return on equity. He provides the analysis and support for PGE's requested RROE of 10.75%.

II. Cost of Long-term Debt

Q. How did you calculate the cost of long-term debt for 2009?

A. PGE Exhibit 901 shows the amount and the effective cost of PGE's outstanding long-term debt for the test year. This includes existing bond issues as of December 31, 2007, as well as bond issues and retirements expected to occur in 2008 and 2009. We calculated the outstanding debt for each year based on the annualization methodology approved in OPUC Order No. 07-015, as well as the other adjustments to debt reflected in that order. The full amount of debt is included for each issuance outstanding at year end and the cost or estimated cost of each issue. We then multiply the amount outstanding in each period by the effective interest rate for each bond issue. The effective interest rate represents the internal rate of return for each of the cash flows associated with each debt issue, including all unamortized call premiums and issuance expenses for debt issues replaced before maturity with less expensive financings. Table 2 below summarizes PGE's cost of long-term debt for 2009.

Table 2
Cost of Long-Term Debt
(Average $000)

	2009
Amount	$1,613,950
Interest Cost	$ 105,988
Effective Interest Rate	6.567%

Q. What future debt issuances did you include in your analysis?

A. We project three new debt issuances in 2008 and 2009 and additionally expect to remarket three issues of pollution control bonds in 2009[2]. Specifically, PGE plans to issue $50 million of long-term (30-year) debt in 2008 and an additional $250 million of 30-year debt

[2] In Order No.08-106, issued January 28, 2008, the Commission approved PGE's financing application to issue up to $250 million of long-term debt.

in 2009. We expect to issue the $250 million in two pieces, $75 million in March 2009 and the remaining $175 million in September 2009. Secondly, we expect to remarket the Colstrip 98A, Boardman 98A, and Colstrip 98B issuances, totaling $142 million, which will contractually be "put back" to PGE on May 1, 2009. We plan to remarket these issues with a fixed rate until their maturity in 2033. We will provide the latest financial information and estimates in our rebuttal testimony as financial conditions and forecasts change.

Q. How did you determine the coupon rate on the new long-term debt issues?

A. We contacted investment bankers and using the information they provided, we expect to issue the debt at the 30-year Treasury rate plus a spread of 200 basis points. This spread represents the appropriate current premium to reflect increased risk for non-callable utility bonds rated "BBB+". We then used the Global Insight U.S. Economic Outlook December 2007 forecast for Treasuries, which is 4.22% in 2008 and 4.89% in 2009. Based on this analysis, the coupon for the $50 million in 2008 would be 6.22%. The two issues totaling $275 million in 2009 would both have an estimated coupon of 6.89%.

Based on information provided by Lehman Brothers (Lehman), the Colstrip 98A and Boardman 98A issuances are estimated to have a coupon of 5.625%, representing the 30-year current interest rates for BBB+ fixed rate tax exempt bonds. The Colstrip 98B issue has an estimated coupon of 5.875%, representing the 30-year current interest rates for BBB+ AMT (Alternative Minimum Tax) fixed rate bonds.

Q. Is there any long-term debt maturing in 2008 or 2009?

A. No.

Q. Has PGE issued or redeemed any long-term debt since PGE filed UE 180 in 2006?

A. Yes. In UE 180, PGE expected to issue $300 million in 2007 and instead issued $375 million. The increase was for additional capital needs. Since interest rates were favorable, PGE also was able to redeem the Trojan 1990B Pollution Control Bonds, which had a coupon of 7.125%.

Q. Have any of the coupon rates for the existing debt listed in Exhibit 901 changed since UE 180?

A. Yes. The coupon on the Coyote 96 floating rate bonds has increased from 3.50% in UE 180 to 4.65% in this proceeding. This security is a floating rate bond and the rate can potentially change each day with the market. Lehman is the remarketing agent for this bond and is responsible for pricing it each day and marketing it to investors.

Q. How did you forecast the 2009 coupon rate for the Coyote variable bonds?

A. To estimate the coupon rate, we relied on Lehman, who estimated that the rate would be approximately 95% of the 2009 Treasury. We then used the December 2007 Global Insight forecast of the 2009 Treasury at 4.89% and took 95% of that rate to arrive at 4.65%. This calculation is also shown in note 24 of PGE Exhibit 901.

III. Capital Structure

Q. How did you determine the appropriate level of common equity for 2009?

A. We evaluated PGE's capital structure using the forecasted income statement and balance sheet for 2009, as well as our expected financings through 2009. Additionally, we considered several factors including PGE's need to maintain its financial strength, flexibility and adequate liquidity; its ability to maintain reliable and economical access to the capital markets; minimizing the cost of capital to customers and shareholders; and the Commission's Order in UE 180 (Order No. 07-015).

Q. Are you seeking a different capital structure than that in UE 180?

A. No. In UE 180, Order No. 07-015 set PGE's regulated capital structure at 50% equity and 50% debt. At that time, our long-term goal was to maintain our capital structure at 50/50. Our long-term goal continues to be to maintain our capital structure at 50% equity and 50% debt, and we expect our regulated equity to exceed 50% by the end of the test period. However, the equity ratio does fluctuate above and below the 50% target level, due to the timing and size of debt and equity issuances. Also, Value Line projects the equity ratio for the comparable sample of utilities used by Dr. Zepp will average approximately 50% equity in 2009. For this rate case, we recommend the same 50% equity and 50% debt capital structure.

Q. Does PGE expect to issue equity in 2009?

A. Yes. In our 2008 financing forecast, PGE plans to issue $200 million in common stock equity in 2009, most likely mid-year. This will be used to reduce the overall leverage impact of the debt financings PGE will issue in 2008 and 2009 to fund its significant capital expenditure program.

Q. Are there issuance costs associated with the new equity?

A. Yes. We estimate that there will be approximately $7 million of issuance costs, primarily for underwriting fees. We have included these costs as an O&M expense by amortizing them over a 10-year period as discussed in PGE Exhibits 100 (Policy) and 200 (Revenue Requirement).

Q. Why does PGE intend to maintain a 50% capital structure?

A. The equity portion of PGE's capital structure is important to offset the leverage and risk PGE will encounter, in part, as it implements a large capital expenditure program over the next few years. It is also required to offset the leverage imputed to PGE due to its above-average reliance on purchased power. Additionally, PGE faces many risks in today's environment and it must be able to maintain a solid capital structure and financial flexibility.

Q. Some rating agencies impute debt on PGE's purchased power contracts and operating leases. Does this have an impact on PGE's credit rating?

A. Yes, indirectly. Standard and Poor's most recent January 2008 evaluation of PGE discusses as a weakness imputed debt on purchased power. The expected increase in purchased power over time "will weaken adjusted capitalization" according to the Standard and Poor's evaluation.

Q. Is this a risk to PGE shareholders?

A. Yes. PGE relied on purchased power contracts for approximately 49% of its power supply portfolio in 2006. The imputed debt of this portfolio, coupled with that of operating leases, adds approximately 5% of additional debt to PGE's capital structure ratios. While a higher debt-to-equity ratio alone may not induce a ratings downgrade, it does add downward pressure to our ratings. If it were a concern that the adjusted percentage of debt is going to remain at a high level in the future, the rating agencies could determine that those ratios are not sufficient to maintain PGE's current BBB+/Baa1 ratings.

Q. What would mitigate this risk?

A. A higher level of equity in PGE's regulated capital structure would help offset the higher adjusted debt ratios discussed above. Additionally, a higher return on PGE's ROE would compensate investors for the additional risk of PGE's heavy reliance on purchased power.

Q. Has the Commission noted any specific risks facing PGE?

A. Yes. In UE 180, Order No. 07-015, the Commission noted that PGE has significant exposure to the wholesale market, especially when compared with PacifiCorp. In particular, PGE faces risk related to the volatility of wholesale electricity prices. Volatility in these markets can affect the availability and the prices of purchased power and demand for energy sales. This volatility can result in the deterioration of market liquidity, increase counterparty credit risk, and impair PGE's ability to manage its energy portfolio. While PGE's power cost adjustment mechanism mitigates this risk to some degree, it does not provide full recovery of all costs outside the sharing cost features. The Commission found that an additional 10 basis points on ROE was appropriate to balance PGE's risk exposure in this area.

Q. What other types of risks does PGE encounter today?

A. PGE faces several other risks and uncertainties, examples include:

- <u>SB 408 and related earnings volatility</u>: Oregon law SB 408 adjusts the way that PGE and other Oregon investor-owned utilities recover income tax expense from customers. SB 408 has financial impacts on PGE, especially earnings volatility.

Earnings volatility increases risks for PGE and its investors, requiring a higher return than otherwise.

- Large capital program over the next three years: PGE has begun a large capital expenditure program that will continue for at least the next five years. As discussed in Section I above, access to the capital markets is critical to fund these expenditures. In the financial markets, PGE has the risk of higher than expected cost or lack of market liquidity to fund the capital program. A strong balance sheet with a higher return on equity reflective of this risk is necessary to remain a marketable company in these volatile financial markets.
- Hydro and wind availability and weather volatility: Weather conditions can adversely affect PGE's revenues and costs. Weather creates risk for PGE in several ways, including:
    - Lower than average stream flows;
    - Lower than average wind availability; and
    - Volatility in electricity usage because of sudden, unexpected weather changes.

  All of the above can potentially force PGE to purchase more spot energy, when the markets may be tight. The higher costs and volatility of weather conditions can increase costs to PGE and its investors, requiring a higher return than otherwise.
- Regional economic weakness: Regional economic weakness can adversely affect PGE's revenues. Weakness in the regional economy, and thus the state of Oregon, can lead to a decline in electricity usage as customers become more

conservative. This can negatively impact PGE's revenues, thereby reducing PGE's profits and returns to investors.

- Rising costs: Rising costs for labor, supplies and materials can also have an adverse affect on PGE's costs, resulting in a lower profit margin and returns to investors.
- Renewable Energy Standard (RES) compliance risk: Oregon RES requires that PGE serve at least 25% of its retail load from renewable resources by the year 2025, with interim requirements in years 2011, 2015 and 2020. PGE faces the risks that lower cost renewables are acquired by other utilities or are unavailable in a timely manner. In addition, PGE will incur other potential risks when placing these resources into rate base, including regulatory risk, transmission congestion, resource availability, etc.
- Uncertainty regarding an adverse Trojan decision: There is uncertainty in the financial markets regarding the ultimate outcome of the legal and regulatory proceedings related to PGE's recovery of its investment in the Trojan Nuclear Plant. This risk is discussed by several financial analysts in their publications. Most recently, in Standard and Poor's January 2008 review of PGE (see PGE Exhibit 903), they listed as a weakness the uncertainties associated with Trojan, including the difficulty to quantify the potential exposure.

Q. Do the financial markets agree that these are risks for PGE?

A. Yes. Both Moody's and Standard & Poor's and several equity analysts have cited one or more of these risks. Standard & Poor's, for example, has referred to PGE's large capital expenditure program, dependence on purchased power, uncertainty regarding Trojan and hydro variability among the potential risks for PGE.

Q. How does PGE manage these risks?

A. PGE can manage some of these risks, but others it cannot. For example, PGE can partially manage unexpected decreases in load caused from economic weakness by delaying some O&M work or hiring. Risks PGE cannot manage include those associated with the government or regulatory framework, such as SB 408. For many risks, even though PGE can partially manage them, PGE remains significantly exposed.

Q. What do these risks mean for the cost of capital you request?

A. All else equal, electric utilities are subject to a variety of risks. Unless those risks are mitigated, the cost of long-term debt, as well as the cost of equity, will be higher than otherwise. The market demands adequate compensation for the risks that equity and debt holders take as they invest in PGE.

IV. Qualifications

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

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs.

Q. Ms. Stathis, please state your educational background and experience.

A. I received a Bachelor of Science degree in Political Science from Willamette University in 1985 and a Post-baccalaureate Certificate in Accounting from Portland State University in 1990. I previously qualified as a Certified Public Accountant in the State of Oregon; however, my license is currently on inactive status.

In 1990, I joined Arthur Andersen, LLP as an accountant and was assigned to the PGE account. In 1994, I joined PGE, beginning as an analyst in Corporate Accounting. While at PGE, I have held various positions including management positions in the budget and power supply risk management departments. I have held my current position as Manager, Corporate Finance and Assistant Treasurer since October of 2005.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
901	PGE 2009 Long-Term Debt
902	PGE 2005-2007 Capital Structure
903	Standard and Poor's January 2008 Credit Opinion of PGE
904	Moody's August 2007 Credit Opinion of PGE

Cost of Long-Term Debt
December 31, 2009

(A)	Type (C)	Description (D)	Issue Date (E)	Maturity Date (F)	Term (G)	Coupon (H)	Gross Proceeds (I)	DD&E Issue Costs (J)	Call Premium & Unamort. DD&E of Refunded Issue (K)		Net Proceeds (L) [I-J-K]	Embedded Cost (M)	Net to Gross Rate (N) [L/i]	Face Amount Outstanding (O)	Net Outstanding (P) [N*O]	Face Amount Weight (Q) [O/Total]	Weighted Rate (R) [Q*M]
1	FMB	5.6675% Series	28-Oct-02	25-Oct-12	10	5.245%	$100,000,000	$11,305,461	$0		$88,694,539	6.823%	88.695%	$100,000,000	$88,694,539	6.196%	0.423%
2	FMB	5.279% Series	08-Apr-03	01-Apr-13	10	4.909%	$50,000,000	$3,914,476	$0		$46,085,524	5.960%	92.171%	$50,000,000	$46,085,524	3.098%	0.185%
3	FMB	5.625% Series	04-Aug-03	01-Aug-13	10	5.398%	$50,000,000	$408,842	$1,946,809		$47,644,349	6.032%	95.289%	$50,000,000	$47,644,349	3.098%	0.187%
4	FMB	6.750% Series	04-Aug-03	01-Aug-23	20	6.523%	$50,000,000	$521,342	$1,946,809		$47,531,849	6.985%	95.064%	$50,000,000	$47,531,849	3.098%	0.216%
5	FMB	6.875% Series	04-Aug-03	01-Aug-33	30	6.648%	$50,000,000	$521,342	$1,946,809		$47,531,849	7.046%	95.064%	$50,000,000	$47,531,849	3.098%	0.218%
6	Series MTN	9.31% Series	12-Aug-91	11-Aug-21	30	9.310%	$20,000,000	$176,577	$0		$19,823,423	9.399%	99.117%	$20,000,000	$19,823,423	1.239%	0.116%
7	FMB	6.310% Series	26-May-06	01-May-36	30	6.310%	$175,000,000	$1,270,865	$6,199,472	*20*	$167,529,663	6.640%	95.731%	$175,000,000	$167,529,663	10.843%	0.720%
8	FMB	6.260% Series	26-May-06	01-May-31	25	6.260%	$100,000,000	$723,857	$4,132,982	*20*	$95,143,161	6.662%	95.143%	$100,000,000	$95,143,161	6.196%	0.413%
9	FMB	5.80% Series	16-May-07	01-Jun-39	32	5.800%	$170,000,000	$1,447,420	$50,969	*25*	$168,501,611	5.861%	99.119%	$170,000,000	$168,501,611	10.533%	0.617%
10	FMB	5.81% Series	19-Sep-07	01-Oct-37	30	5.810%	$130,000,000	$1,627,092	$0		$128,372,908	5.899%	98.748%	$130,000,000	$128,372,908	8.055%	0.475%
11	FMB	5.80% Series	12-Dec-07	01-Mar-18	10	5.800%	$75,000,000	$637,500	$0		$74,362,500	5.914%	99.150%	$75,000,000	$74,362,500	4.647%	0.275%
12	FMB	2008 Series	01-Aug-08	01-Aug-38	30	6.220%	$50,000,000	$480,000	$0		$49,520,000	6.292%	99.040%	$50,000,000	$49,520,000	3.098%	0.195%
13	FMB	2009a Series	01-Mar-09	01-Mar-39	30	6.890%	$75,000,000	$720,000	$0		$74,280,000	6.967%	99.040%	$75,000,000	$74,280,000	4.647%	0.324%
14	FMB	2009b Series	01-Sep-09	01-Sep-39	30	6.890%	$175,000,000	$1,680,000	$0		$173,320,000	6.967%	99.040%	$175,000,000	$173,320,000	10.843%	0.755%
15	Notes	7.875% Series	13-Mar-00	15-Mar-10	10	7.875%	$149,250,000	$1,472,800	$1,266,000	*17*	$146,511,200	8.128%	98.165%	$149,250,000	$146,511,200	9.247%	0.752%
16	PCB	Brdmn 98A Fixed	28-May-98	01-May-33	35	5.625%	$23,600,000	$165,830	$1,082,304	*5,16,18,23*	$22,351,866	5.898%	94.711%	$23,600,000	$22,351,866	1.462%	0.086%
17	PCB	Clstrp 98A Fixed	28-May-98	30-Apr-33	35	5.625%	$97,800,000	$687,210	$1,578,566	*6,16,18,23*	$95,534,224	5.661%	97.683%	$97,800,000	$95,534,224	6.060%	0.343%
18	PCB	Colstrip 98B Fixed	28-May-98	30-Apr-33	35	5.875%	$21,000,000	$147,560	$411,650	*16,18,23*	$20,440,790	5.943%	97.337%	$21,000,000	$20,440,790	1.301%	0.077%
19	PCB	Trojan 85A Fixed	01-Jul-98	01-Apr-10	25	4.800%	$20,200,000	$218,352	$244,162	*16*	$19,737,486	5.058%	97.710%	$20,200,000	$19,737,486	1.252%	0.063%
20	PCB	Trojan 85B Fixed	01-Jul-98	01-Jun-10	25	4.800%	$16,700,000	$180,519	$184,473	*16*	$16,335,008	5.046%	97.814%	$16,700,000	$16,335,008	1.035%	0.052%
21	PCB	Trojan 90A Fixed	01-Jul-98	01-Aug-14	16	5.250%	$9,600,000	$103,771	$184,980	*16*	$9,311,249	5.537%	96.992%	$9,600,000	$9,311,249	0.595%	0.033%
22	PCB	Coyote 96 Float	01-Dec-96	01-Dec-31	35	Variable	$5,800,000	$0	$143,090	*24*	$5,656,910	4.828%	97.533%	$5,800,000	$5,656,910	0.359%	0.017%
		Loss on Reacquired Debt							$374,581		($374,581)						
		Total Debt					$1,613,950,000	$28,410,815	$21,693,656		$1,563,845,529			$1,613,950,000	$1,564,220,110	100.00%	6.544%
		Cost of LT Debt (includes loss from reacquired)															**6.567%**

Losses on Reacquired Debt	Reacquired	Gross Proceeds	Total Gain/Loss to Amortize	Annual Expense
13.50% FMB Due 10/1/12	25-Apr-88	$75,000,000	$8,989,952	$374,581
				$374,581

FOOTNOTES

5 PCB Series Due 4/1/84-11 - PGE refunded its $25.45m Fixed Rate Port of Morrow PCB scheduled to expire serially from 1984-2011 with 26 year variable rate PCB due 6/1/13. Unamortized debt expense and call premium totaled $1,395,954, which is being recovered over the life of the replacement PCB.

16 On 5/28/98, PGE re-marketed and extended the Boardman 88A (now Boardman 98A), the Colstrip 83A-D, the Colstrip 84 (these issues combined to form Colstrip 98A), and the Colstrip 86 (now colstrip 98B). The previous issue costs and premiums were amortized to 5/28/98 and included in the call premium column. The remarketing costs are included in the Issue Costs column. All of the above issues' coupon costs were fixed. On 7/1/98, the Trojan variable rates were fixed, although not extended.

17 One time buydown event of $750,000 in July 2002.

18 Ledger # changed between 2000&2001 when interest rate swapped from floating to fixed.

20 There was a $12 million call premium on the 8.125% redeemed issue. A portion was disallowed in UE 180. The remainder is rolled into the new debt and will be paid over the period of the April 2006 issuance.

23 **PCB's** - Put back in May 2003 to 2009. May 1 2009, will be put back for the remaining life - until 2033. The average rate for 2009 is used to calculate the embedded cost.

Calculations for fees and adjustments

	%	Amount	Old Rate 2003-5/2009	New Rate 5/2009-2033	Weighted Average Rate 2009	Old Unamort. DD&E + Previous Issue costs	Amt DD&E remaining at May 1, 2009	Fees for the Reissue: Allocate $75,000 fee for 2009 re-issue	60 bp	Total Fee
G21186 - PCB Brdman 98A Fixed -	0.1657	23,600,000	5.200%	5.625%	5.483%	$1,352,880	$ 1,082,304	$ 12,430	153,400	$ 165,830
G21185 - Clstrp 98A Fixed	0.6868	97,800,000	5.200%	5.625%	5.483%	$1,973,208	$ 1,578,566	$ 51,510	635,700	$ 687,210
G21184 - Colstrip 98B Fixed	0.1475	21,000,000	5.450%	5.875%	5.733%	$514,563	$ 411,650	$ 11,060	136,500	$ 147,560
	100.00%	142,400,000				$3,840,651	$3,072,521	$75,000	$925,600	$ 1,000,600

24 Coyote Bonds: 2009 forecast using 95% of a 30 yr Treasury. Used Global Insight for the T forecast.

	Amount	2009 Treasury	95%	2009 forecast	old DD&E from 6/06	Amt remaining at 12/31/08
Calculations:	5,800,000	4.89000%	95.0000%	4.645500%	$ 159,350	$ 143,090

25 Early redemption of 5.1MM Trojan 1990B PCB's in June 2007. Unamortized loss of $50,969 are added to the 5.80% series $170MM issued in May 2007 as those dollars were used to redeem the PCB's.

PGE's Capital Structure

(in millions)

	Actuals		
	12/31/2005	**12/31/2006**	**09/30/2007**
Long Term Debt (excluding current maturities)	$ 862	$ 937	$ 1,238
Common Equity	$ 1,215	$ 1,224	$ 1,303
Total Capitalization	$ 2,076	$ 2,161	$ 2,541
Equity Ratio	**59%**	**57%**	**51%**

Amounts do not include short term debt or current maturies of long term debt

2005 Equity include $17.5 million of preferred stock

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January 31, 2008

Portland General Electric Co.

Primary Credit Analyst:
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Portland General Electric Co.

Major Rating Factors

Corporate Credit Rating

BBB+/Stable/A-2

Strengths:

- An above-average framework for the recovery of capital and power costs that includes: a forecast test year for general rate cases (GRCs), which has allowed the company to collect in rates sizable new plant additions when they come online; an annual mechanism to update power costs based on projections; and a power cost adjuster that tracks differences between actual costs and those authorized in rates--although we would note that the threshold for recovery of deferrals is high;
- The company's Boardman coal plant outage is behind it; in 2007, operational performance returned to normal and the Public Utility Commission of Oregon (OPUC) authorized to defer in future rates a portion of costs the company expensed in 2005 and 2006;
- A favorable maturity schedule and minimal reliance on floating rate debt, including short term debt;
- Retail electric rates that, while slightly above average for the region, remain reasonably competitive; they could, however, come under pressure due to the company's expansion program; and
- The absence of unregulated activities, with a focus on core utility operations.

Weaknesses:

- Uncertainties associated with resolving the return of Trojan nuclear power plant costs, which we do not expect will happen in 2008, despite the likelihood that the OPUC will rule on the issue in the next six months--the company's potential exposure is difficult to quantify but could be large;
- A sizable five-year capital program of $2.3 billion; while the company expects a reasonable amount of debt to finance these investments, failure to achieve earnings due to slowing growth, anemic regulatory support, or other factors could result in incremental debt burdens;
- Somewhat weak forecast adjusted financial measures, particularly the ratio of funds from operations (FFO) to total adjusted debt, although we expect this to be limited to the years when capital spending is highest, in 2009 and 2010;
- Reliance on purchases for about 25% of its power supply portfolio (excluding long-term hydro contracts); although the company's recent plant additions should reduce this dependence, the debt imputed for purchased power obligations is expected to increase over time, which will weaken adjusted capitalization; and
- Wholesale market exposure due to dependence on purchased power as well as hydroelectric and gas-fired production.

Rationale

The 'BBB+' rating assigned to Portland General Electric (PGE) reflects a 'strong' business profile and an 'intermediate' financial profile. The business profile is underpinned by a supportive regulatory framework for the recovery of costs, the resolution of the extended Boardman outage, both from an operational and regulatory perspective, the completion of a 400 MW gas plant (Port Westward) and 125 MW wind farm (Biglow I) in 2007, and the timely inclusion of these assets in the rate base.

Challenges to the business and financial profile include a large capital program, looming risks associated with the Trojan plant, and ongoing exposure to low hydro, which supplies about 26% of the company's total energy. While the recovery of costs associated with the now-closed Trojan nuclear plant pose risks to the credit profile of the company, it is uncertain whether the company will ultimately be required to provide a customer refund, what the amount is, if any, and the time period over which a rebate, if ordered, would occur. While the OPUC is expected to issue a decision on Trojan issues within the next six months, further litigation seems likely, and a final resolution could be years away.

PGE is an integrated electric utility serving more than 800,000 customers in northwestern Oregon, including the cities of Portland and Salem, or roughly 45% of the state's population. As of Sept. 30, 2007, PGE had about $1.2 billion in total debt outstanding.

The company benefits from an annual power cost update mechanism and a power cost adjuster. PGE files its expected net variable power costs in April of every year (including contracts coming on line). Net variable power costs are updated in August and again in November, with final retail rates reflecting forward price expectations going into effect Jan. 1. Differences between actual costs and those approved as part of this process are recovered under the companies power cost adjustment mechanism (PCAM).

The PCAM puts the company at risk to absorb a fairly high level of costs before it is eligible for a deferral through the application of an asymmetric dead band. For example, based on 2007, the dead band requires PGE to absorb an estimated $23.4 million in cost overruns before the company would be eligible to collect a deferral from customers under a 90%-10% sharing mechanism. Actual collection of deferrals is subject to an earnings test, and based on a currently authorized 10.1% return on equity (ROE), the company's actual ROE would have to be below 9.1% for it to collect on the deferral. (In 2007, the company is expected to have overcollected on costs, with a future customer rebate in the range of $14 million).

PGE also has a renewable energy tracker that allows for recovery of renewable investments in retail rates. In 2007, Biglow I, a 125 MW wind farm came online, and rates reflect a 0.6% increase beginning in 2008 needed to recover the plant's costs and a company return. Biglow I was added to the rate base through the 2007 GRC, but future additions mau use the tracker.

As a result of these mechanisms, GRCs are needed only for the purposes of updating operations and maintenance costs and adding non-renewable capital additions. While the company's 2007 GRC outcome disappointingly lowered retail rates by nearly $21 million, the decision was supportive of Port Westward cost recovery, allowing rates to be adjusted upwards in June, and it rejected consumer advocates' requests to reexamine rates because the plant's online date was delayed slightly.

PGE is pursuing a major resource acquisition program to reduce its dependence on short-term power purchases to about 30%-35% (including long-term hydro contracts) of its energy requirements and to increase its ownership of generating capacity. While we see the company's regulatory framework as positive, rate relief throughout the next five years will need to occur to support the company's financial metrics.

PGE's recent financial metrics are adequate for the rating. Adjusted funds from operations (FFO) coverage of interest was 3.6x for the 12-month period ended Sept. 30, 2007, while adjusted FFO coverage of debt was 19.1%, which is somewhat weak for the rating. The adjusted total debt-to-capitalization ratio is 53.4%, also slightly weak, but in line with our expectations for 2007, given the company expects to spend approximately $471 million on capital investments and has issued about $380 million in debt. While management's target of an unadjusted 50% equity layer is expected to support PGE's rating at the 'BBB+' level, it may not be achieved in the next few years. Debt leverage is expected to hover around an adjusted 55% in 2008 and 2009, as capital additions peak. With the realization of rate relief and retained earnings, capitalization should start improving thereafter. We expect the company to issue equity as needed, particularly if it is unable to trend its capital structure back toward 50% after 2009.

Short-term credit factors

The rating on PGE's short-term debt is 'A-2', which reflects adequate liquidity, modest debt maturities, increased but manageable reliance on external borrowings to fund capital expenditures, and our expectation that the utility will continue to generate stable cash flow.

The company's commercial paper (CP) program of $400 million is backstopped by a $400 million, five-year unsecured revolving credit facility that provides adequate liquidity for operations. The facility has an accordion feature that allows the company to increase the facility size by $150 million, but bank approval is required. The credit facility expires in July 2012.

The company's CP program was untapped at Sept. 30, 2007; the company had utilized approximately $14 million in letters of credit, leaving $386 million in unused capacity. The facility contains a financial covenant limiting leverage to 65% of total capitalization, with which the company was in compliance as of Sept. 30, 2007. At Sept. 30, 2007, the company's consolidated indebtedness to total capitalization ratio, as calculated under the facility, was 48.7%.

Near-term debt maturities are minimal. Given its substantial purchased power requirements, PGE has some potential exposure to collateral calls in the event of market price swings or lowered ratings. As of Sept. 30, 2007, PGE had posted approximately $43 million of collateral, consisting of $4 million in letters of credit and $39 million in cash. A lowering of its rating by a single rating agency to speculative grade would require additional collateral that was estimated to be about $8 million at year-end 2007; a lowered rating by two agencies would require $20 million as of the same date.

Outlook

The stable outlook reflects that PGE will be able to maintain adequate financial performance through supportive regulation, which will be required to implement its large capital program. While some weakening may occur through 2009 in its credit metrics, we expect this would be temporary. Meaningful financial deterioration caused by low hydro conditions, stagnant growth, poor regulatory outcomes, or other pressures could result in lowered ratings or an outlook revision.

The outlook does not capture the event risk presented by the ongoing and longstanding potential for a rebate of past costs collected for the Trojan nuclear plant. This litigation risk, which has been ongoing since 1998, is likely to continue for at least several more years before sufficient clarity will exist to assess the rating consequences.

Accounting

PGE's financial statements for fiscals 2006 have been audited by Deloitte & Touche LLC, which provided an unqualified opinion. PGE's trading activities, which are meant purely to optimize its power supply portfolio, do not materially affect the financial statements. While some derivatives are marked to market, others qualify for the normal purchases and sales exception under Financial Accounting Standard (FAS) 133 and are accounted for on an accrual basis. Yet others are accounted for as cash flow hedges under FAS 133 but are not recorded under "other comprehensive income" because they are included in the annual update tariff and thus subject to regulatory deferral under SFAS 71. We consider the cash effect of these transactions in our calculations of FFO.

We adjust PGE's financial statements mainly for purchased power agreements (PPAs) and operating leases and postretirement benefit obligations, which totaled $264 million in 2006. The capitalization of PPAs assumes a 25% risk factor. Fifty percent of the total payments were assumed to contribute toward capacity payments in contracts with an all-in $/ MWh price.

Table 1

Portland General Electric Co. -- Peer Comparison*

Industry Sector: Electric				
	Portland General Electric Co.	**IDACORP Inc.**	**PacifiCorp**	**Puget Energy Inc.**
Rating as of Jan. 31, 2008	BBB+/Negative/A-2	BBB+/Negative/A-2	A-/Stable/A-1	BBB-/Watch Neg/--
	--Average of past three fiscal years--			
(Mil. $)				
Revenues	1,473.3	865.7	3,699.9	2,559.3
Net income from cont. oper.	75.7	88.9	306.8	146.3
Funds from operations (FFO)	285.7	182.0	893.2	436.5
Capital expenditures (capex)	278.8	205.2	1,087.4	670.0
Cash and investments	112.7	28.6	126.0	21.5
Debt	1,236.5	1,292.8	5,440.0	3,203.5
Preferred stock	0.0	0.0	41.3	94.5
Equity	1,182.0	1,016.0	3,766.1	1,987.5
Debt and equity	2,418.6	2,308.8	9,206.0	5,191.0
Adjusted ratios				
EBIT interest coverage (x)	2.2	2.3	2.6	1.9
FFO int. cov. (x)	3.9	3.5	3.8	3.0
FFO/debt (%)	23.1	14.1	16.4	13.6
Discretionary cash flow/debt (%)	(7.2)	(5.2)	(7.1)	(12.9)
Net cash flow/capex (%)	81.2	64.7	70.2	51.3
Debt/total capital (%)	51.1	56.0	59.1	61.7

Table 1

Portland General Electric Co. -- Peer Comparison* (cont.)				
Return on common equity (%)	5.0	8.0	7.4	7.2
Common dividend payout ratio (un-adj.) (%)	78.4	55.4	42.3	63.6

*Fully adjusted (including postretirement obligations).

Table 2

Portland General Electric Co. -- Financial Summary*					
Industry Sector: Electric					
	--Fiscal year ended Dec. 31--				
	2006	**2005**	**2004**	**2003**	**2002**
Rating history	BBB+/Negative/A-2	BBB+/Stable/A-2	BBB+/Watch Neg/A-2	BBB+/Developing/A-2	BBB+/Developing/A-2
(Mil. $)					
Revenues	1,520.0	1,446.0	1,454.0	1,752.0	1,855.0
Net income from continuing operations	71.0	64.0	92.0	56.0	66.0
Funds from operations (FFO)	258.2	258.0	340.7	260.4	249.9
Capex	374.9	251.0	210.4	164.0	176.9
Cash and investments	12.0	122.0	204.0	109.0	51.0
Debt	1,348.2	1,197.7	1,163.7	1,207.4	1,271.3
Preferred stock	0.0	0.0	0.0	0.0	27.0
Equity	1,224.0	1,112.5	1,209.6	1,117.7	1,072.8
Debt and equity	2,572.2	2,310.2	2,373.3	2,325.1	2,344.1
Adjusted ratios					
EBIT interest coverage (x)	2.0	2.0	2.5	1.9	2.3
FFO int. cov. (x)	3.5	3.6	4.7	3.5	3.8
FFO/debt (%)	19.2	21.5	29.3	21.6	19.7
Discretionary cash flow/debt (%)	(23.8)	(4.3)	8.9	9.6	10.1
Net cash flow/capex (%)	61.4	43.0	161.9	158.2	140.1
Debt/debt and equity (%)	52.4	51.8	49.0	51.9	54.2
Return on common equity (%)	3.9	4.2	6.8	4.2	5.8
Common dividend payout ratio (un-adj.) (%)	39.4	234.4	0.0	0.0	0.0

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of PGE Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*								
	--Fiscal year ended Dec. 31, 2006--							
Portland General Electric Co. reported amounts								
	Debt	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	1,084.0	378.0	378.0	159.0	69.0	106.0	106.0	371.0

Table 3

Reconciliation Of PGE Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*(cont.)

Standard & Poor's adjustments								
Operating leases	90.2	7.5	6.6	6.6	6.6	0.9	0.9	11.9
Postretirement benefit obligations	13.0	(5.0)	(5.0)	(5.0)	--	(0.7)	(0.7)	--
Capitalized interest	--	--	--	--	8.0	(8.0)	(8.0)	(8.0)
Power purchase agreements	161.0	12.6	12.6	12.6	12.6	--	--	--
Reclassification of nonoperating income (expenses)	--	--	--	17.0	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	176.0	--
U.S. decommissioning fund contributions	--	--	--	--	--	(16.0)	(16.0)	--
Total adjustments	264.2	15.1	14.2	31.2	27.2	(23.8)	152.2	3.9

Standard & Poor's adjusted amounts

	Debt	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Capital expenditures
Adjusted	1,348.2	393.1	392.2	190.2	96.2	82.2	258.2	374.9

*Portland General Electric Co. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of January 31, 2008)*

Portland General Electric Co.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Preferred Stock	
Local Currency	BBB-
Senior Secured	
Local Currency	A
Senior Unsecured	
Local Currency	BBB
Corporate Credit Ratings History	
31-Jan-2008	BBB+/Stable/A-2
27-Feb-2006	BBB+/Negative/A-2
20-Sep-2005	BBB+/Stable/A-2
11-Mar-2005	BBB+/Developing/A-2
10-Mar-2004	BBB+/Watch Neg/A-2

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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Moody's Investors Service

Global Credit Research
Credit Opinion
17 AUG 2007

Credit Opinion: Portland General Electric Company

Portland General Electric Company

Portland, Oregon, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa2
First Mortgage Bonds	Baa1
Senior Secured	Baa1
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Preferred Stock	Ba1
Commercial Paper	P-2

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Key Indicators

Portland General Electric Company

	LTM (6/07)	2006	2005	2004
(CFO Pre-W/C + Interest) / Interest Expense [1]	**7.1x**	**5.1x**	**5.0x**	**6.2x**
(CFO Pre-W/C) / Debt [1]	**35.5%**	**23.6%**	**28.5%**	**35.7%**
(CFO Pre-W/C - Dividends) / Debt [1]	**30.9%**	**21.2%**	**13.5%**	**35.7%**
Debt / Book Capitalization	**43.9%**	**44.8%**	**41.4%**	**39.7%**
ROE (NPATBUI / Avg. Equity) [2]	**11.6%**	**5.4%**	**4.5%**	**6.7%**
Dividends as a % of NPATBUI [2]	**38.5%**	**43.1%**	**266.6%**	**0.0%**

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] NPATBUI is Net Profit After-tax Befor Unusual Items

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Portland General Electric Company (PGE) is a vertically integrated electric utility company, with headquarters in Portland, Oregon, providing regulated service to about 802,000 retail accounts throughout a service territory spanning roughly 4,000 square miles. The service territory includes 52 cities (Portland and Salem being the two largest), and has a population of about 1.6 million or 43% of Oregon's population. PGE's common stock is now listed and traded on the New York Stock Exchange since it is no longer a wholly-owned subsidiary of Enron Corp. following cancellation of PGE's old stock and issuance of 62,500,000 shares of new stock. Subsequent to this step, substantially all of PGE's stock has either been distributed to Enron creditors holding allowed settled claims or sold by the Disputed Claims Reserve trust to the public.

PGE's net plant in service approximates $2.3 billion, close to 90% of which is comprised of electric generation, transmission and distribution infrastructure. During 2007, PGE retail load is estimated to be served by hydro power sources (29.1%), coal-fired sources (17.7%), gas/oil-fired sources (31.1%), and purchased power (22.1%). The degree of dependence on gas/oil fired sources has increased due to the start of commercial operation at the 400-MW natural gas fired Port Westward plant in June 2007. In turn, the reliance on purchased power is expected to decline not only because of the addition of Port Westward, but because of better performance by the Boardman coal plant and improved hydro conditions compared to 2006. As wind power projects are added in the future, the dependence on purchased power should continue to decline even further.

The economy in PGE's service territory has supported annualized customer growth of about 1.7% over the past ten years and modest annualized load growth during the same time period. About 85% of PGE's revenues are derived from the sale of electricity to the more stable and predictable residential and commercial customers. The company's industrial sales, which can be subject to more variability, are spread among the technology, paper, retail, manufacturing, and services sectors. About 61% of PGE's 2006 industrial sales were made to the technology and paper sectors combined. Importantly, there is not undue concern about customer concentration, with no single customer accounting for more than 4% of retail revenues. PGE's larger industrial customers include Boeing, Boise Cascade, Intel, and Nike.

PGE's retail rates are subject to the regulatory jurisdiction of the Oregon Public Utility Commission (OPUC).

Rating Rationale

PGE's ratings take into account several key factors, including its business and regulatory risk profile, its financial metrics, its resource strategy and supply risk, and its liquidity. We currently view PGE's business and regulatory risk profile as consistent with the high end of the Baa rating category. The company's recent financial metrics, including the utility's coverage of interest and debt by cash flow from operations (exclusive of working capital changes) and its adjusted debt to adjusted capitalization, are arguably more consistent with some A rated issuers; however, our ratings for PGE take into account that the most recent levels of key credit metrics are, in our opinion, not sustainable and more likely to revert to the higher end of the Baa rating category in the near term. PGE's resource strategy and liquidity profile are deemed to be appropriate and more than adequate, respectively, for its current operating profile. Collectively, our assessment of these and the other key factors is consistent with the current Baa2 rating and stable outlook assigned to PGE's senior unsecured debt and are discussed in greater detail below.

BUSINESS AND REGULATORY RISK PROFILE

Our assessment of PGE's business and regulatory risk profile takes into account the vertically integrated nature of the utility's operations, the company's proactive and collaborative approach to dealings with the staff and commissioners serving on the OPUC, and the benefits derived from using a forward test year as part of the rate setting process, as well as the recent implementation of a new mechanism to allow PGE to achieve more stable earnings by sharing with customers a portion of the higher power costs that are periodically incurred due to the variability in hydro and commodity market conditions and fluctuations in owned plant operations. The assessment of PGE's credit quality also considers the complete separation in April 2006 from Enron Corp., which had been PGE's parent company dating from 1997. With regard to the latter point, although PGE remained insulated from Enron's bankruptcy proceedings, there were lingering concerns about PGE's future ownership until the OPUC denied Texas Pacific Group's request for approval to acquire PGE in a highly leveraged transaction, ultimately leading to the process of issuing stock to creditors and the public which began in April 2006 and finally concluded in June 2007 as described above.

REGULATORY REQUIREMENT FOR MINIMUM REQUIRED COMMON EQUITY LIFTED

The regulatory requirement of maintaining a minimum common equity ratio of 48% is no longer applicable following completion of the distribution and sale of PGE's stock as described above. We are not unduly concerned about this regulatory change given management's prudent financing strategies demonstrated throughout its ownership by Enron and the utility's stated objective to maintain a roughly 50/50 debt to equity mix in its capital structure going forward. Any unexpected shift towards a more aggressive financing strategy could create downward pressure on PGE's ratings.

GENERAL RATE CASE DECISION CREATES BETTER ALIGNMENT OF COSTS AND CUSTOMER RATES

PGE received approval for about two-thirds of the revenue increase requested in rate proceedings initiated in March 2006 and concluded in January 2007. Specifically, PGE's overall revenue increase approved on January 12, 2007 amounted to $94.6 million or 6.4% versus $143 million or 8.9% originally requested. About 5.1% of the increase was driven by power and fuel costs incorporating PGE's annual power cost filing under the Resource Valuation Mechanism (RVM) as part of the general rate case, while the balance was tied to recovery of investments in the Port Westward natural gas-fired generation plant (see below for more details) and other non-power-related costs of service. Historically, the RVM proved to be a reasonably effective means for PGE to update its variable power costs annually for inclusion in base rates for the following year. Under guidelines established in Oregon's energy industry restructuring law, the RVM used both market prices and values associated with the utility's resources in establishing power costs and setting prices. However, as part of the decision in this most recent rate case, the OPUC approved an annual power cost update tariff as a replacement for the RVM. Use of the annual power cost update tariff as a replacement for the RVM provides a means for rate adjustments to reflect updated forecasts of net variable power costs for future calendar years. Under the replacement approach for the RVM, PGE benefits from a closer match between costs incurred and rates charged.

The effective date of the portion of the rate increases tied to the new gas-fired Port Westward plant coincided with commencement of commercial operation, which took effect in June 2007.

Overall, we consider the outcome of this proceeding to be reasonable and our current ratings for PGE's debt assume a continuation of reasonably supportive outcomes in any future proceedings.

POWER COST ADJUSTMENT MECHANISM (PCAM)

The slow pace of deregulation under Oregon law has effectively been neutral to PGE's credit quality and the OPUC has periodically supported company requests for recovery of PGE's deferred energy costs. This was accomplished via OPUC approval of a temporary PCA mechanism during certain periods. At other times, management was inclined to forego such requests because the amounts involved were not as large and other cost efficiency measures proved sufficient to minimizing the financial impact. As part of the decision on January 12, 2007, the OPUC structured and approved a new power cost adjustment mechanism (PCAM). Under a formulaic earnings test, the PCAM provides for the possibility that PGE could either refund or recover up to 90% of the difference between actual and forecast power costs (outside of the defined deadband), depending on the extent to which PGE's actual earnings vary from its allowed return on equity set by the OPUC (i.e. 10.1% in the last rate case decision). We believe that the availability of additional gas-fired generation at the Port Westward site and the PCAM should help substantially to mitigate PGE's exposure to hydroelectric volatility that was evidenced by persistent drought conditions that prevailed in the Northwest during 2000 - 2005.

HIGHER THAN HISTORICAL CAPITAL PROGRAM FOR THE NEXT COUPLE OF YEARS

Since PGE elected to permanently shut down its Trojan nuclear power plant in the early 1990's, it has relied extensively on purchased power arrangements to meet its retail customers' power needs. More recently, PGE, like many of its peers in the Northwest, has adopted plans to make itself less dependent on the wholesale power market. As this strategy plays out, PGE faces an increased capital budget, especially over the next two years as it adds to its owned generation (i.e. Biglow Canyon Wind Farm project) and maintains reliability of its existing infrastructure. PGE's capital expenditures were $371 million in 2006; however, the company's latest estimates point to capital spending in the range of $525 to $535 million in 2007, which includes about $200 million for Phase I of the Biglow Canyon Wind Farm project. Looking beyond 2007, PGE's capital requirements are expected to decline to a range of $310 - $330 million in 2008 and then increase to a range of $650 - $670 million in 2009. PGE's forecast for capital expenditures include $550 - $650 million on Biglow Canyon II and III through 2010. This part of PGE's resource strategy would allow the utility to develop up to 450 megawatts of renewable energy capacity.

Moody's ratings of PGE's debt take into account the likelihood that the utility will need to externally fund a portion of these investments which the company should be able to do while maintaining its currently sound financial profile (including debt not to exceed 50% of total capitalization) and sufficient liquidity. Consistent with this view, we note that PGE privately issued $170 million of first mortgage bonds in May 2007 and has $130 million of long-term funds available on a delayed draw basis as a result of a private placement priced in April 2007. We expect that PGE will draw on these funds later this year.

BOARDMAN PLANT OUTAGE

During the fourth quarter of 2005 and the first half of 2006, PGE experienced increased working capital needs to fund replacement power costs because of the unplanned outage at its Boardman coal plant. In February 2007, the OPUC concluded a regulatory proceeding in which PGE sought approval to defer a portion of replacement power costs incurred during the outage so that they might be considered for recovery in a future rate case. PGE has already dealt with the higher working capital requirements that resulted from the outage and the effects from the lower earnings reported during those quarterly periods that were affected. While PGE sought to defer slightly less than half of the $92 million in related replacement power costs incurred, the OPUC determined that PGE could defer only $26.4 million of such costs, citing that portion as the extraordinary portion that should be entitled to such treatment under Oregon regulatory statutes. In our view, it appears that the OPUC adopted a different view than PGE did as for the extent to which the extraordinary costs could have been avoided. Nevertheless, PGE's future financial metrics could receive a modest boost if the OPUC ultimately determines that the $26.4 million portion of unanticipated costs were prudently incurred and therefore entitled to be recovered in future rates.

SATISFACTORY RESOLUTION OF VARIOUS CONTINGENCIES RELATED TO PAST OWNERSHIP

Some of the more significant contingencies that PGE might have had to deal with because of its prior ownership by Enron included taxes and pension benefits. Various agreements entered into between Enron and PGE, including a Separation Agreement, have generally provided for resolution of these issues and have been factored into PGE's ratings.

LITIGATION OVER PGE'S EARNED RETURNS ON PAST INVESTMENTS IN ITS TROJAN NUCLEAR PLANT

In 1995, the OPUC issued an order granting PGE's right to recovery of, and a return on, 87% of its then remaining investment in Trojan nuclear plant costs, as well as full recovery of its estimated decommissioning costs through 2011. At this point, there are no legal questions surrounding PGE's right to full recovery of the decommissioning costs. However, there have been periodic legal challenges and law suits that have been raised at various points in time related to OPUC's 1995 decision. At this time, the issues apparently relate primarily to PGE's right to retain amounts recovered through past rates that provided for return on the 87% remaining investment in Trojan. It is unclear at this point precisely what PGE's financial exposure might be, if any, and PGE has not taken any reserves related to the matter. Nevertheless, as a precaution, PGE is keeping the size of its bank credit facility above what it might otherwise normally have in place. The extra liquidity is intended in part to provide flexibility, if needed, to post collateral in conjunction with pursuing legal rights of appeal in the event of any adverse ruling. At this stage, the Oregon Supreme Court has ruled that a class action lawsuit relating to this matter must remain on hold pending completion of the OPUC's pending review of the rate matter following an earlier remand to the OPUC by the Marion County Circuit Court. Although the OPUC heard oral arguments in the regulatory proceedings related to this issue during August 2007, given the various views expressed and litigation relating to this matter it remains unclear precisely when the matter will be resolved. Moody's will continue to monitor this issue, but does not believe it is cause for undue concern at this time.

OREGON SENATE BILL 408 (SB 408):

SB 408 seeks to adjust the way in which PGE and most other Oregon-based investor-owned electric and gas utilities collect income taxes from ratepayers. On the heels of passage of this legislation, the OPUC adopted rules in mid-September 2006 to govern the utilities as they implement the law. Going forward, the utilities will be required to file annual tax reports with the OPUC by mid-October comparing the taxes actually paid by the utility for a specified period with the authorized amount collected in actual rates charged to customers during that same period. Subject to certain formulas, the utilities would be required to either provide refunds to customers for over-collected amounts or assess additional charges to customers for under-collected amounts.

After assessing its own situation relating to SB 408, PGE took a non-cash $42 million (pre-tax) reserve in 2006 in anticipation of the refunds it might be required to provide to its customers. For 2007, PGE is anticipating a better match between taxes that will be paid versus amounts to be collected through rates and is currently estimating an undercollection of about $10 million for the year. In a recent development, the OPUC has issued an order that could result in additional refunds related to a period covering late 2005. PGE will revisit this issue on a quarterly basis and establish reserves or regulatory assets as appropriate. The timing of the cash impact of any required refunds related to the 2006 tax year are not expected to occur until after June 1, 2008. In the meantime, we expect further scrutiny of SB 408 by legislators, regulators, and the utilities in Oregon given what appear to be a fairly widespread view that implementation of the bill is causing unintended negative consequences for the utilities. As additional information unfolds, we will assess the degree of credit impact for PGE.

FINANCIAL METRICS

In earlier reports, we have said that PGE's financial metrics during the period of Enron's bankruptcy could have supported ratings higher than the levels maintained during that period. However, the ratings were constrained during that period by uncertainty regarding the company's on-going ownership and potential contingent liabilities. More recently, for the years ended December 31, 2005 and 2006, PGE's key metrics, including its coverage of interest and debt by cash flow from operations (exclusive of working capital changes), were down from more robust levels achieved in 2004. This trend resulted from lower earnings in the second half of 2005 and the first half of 2006, largely attributable to the higher power supply costs incurred due to the prolonged outage at the Boardman coal plant. In addition, PGE experienced increased winter storm restoration costs during the winter of 2006 and higher customer support costs.

For the trailing 12-months ended June 30, 2007, PGE's cash flow from operations (exclusive of working capital changes) covered its interest and debt by a robust 7.1x and 35.5%, respectively, which is comparable to the levels achieved in 2004. The improvement reflects the return to normal operations at the Boardman coal plant and the rolling off of negative financial effects of the outage in our calculations for the most recent trailing 12 months. Although PGE's coverage metrics for the most recent 12-month period are, at a minimum, within the range more typical for an A-rated regulated electric utility company conducting business in a supportive regulatory environment, as outlined in Moody's Global Rating Methodology for Regulated Electric Utilities, we do not expect PGE to sustain coverage metrics at these levels over the next several years. Nevertheless, when taking into account the reasonable outcome in PGE's last rate case and the effects of recent and expected issuance of incremental debt, while also assuming PGE can maintain normal operations at the Boardman plant, become less reliant on higher cost purchased power in the future, and adequately cope with the financial impacts of SB 408, we expect PGE to produce coverage of interest and debt above 4x and in the low-to-mid-20% range, respectively, over the next few years. Achievement of financial metrics at these levels would be in line with appropriate levels for PGE's current ratings.

With respect to PGE's capital structure, we note that the company has maintained a fairly thick equity cushion over the years when compared to its peers; however, as indicated previously, we expect an increase in the debt level as PGE finances a higher than historical level of capital expenditures over the next two to three years while not exceeding 50% of total capitalization based on management's public assertions. A 50% debt component in the capital structure is well within the range we consider appropriate for a Baa-rated utility according to our methodology for regulated electric utilities.

Liquidity

PGE currently has a Prime-2 short-term rating for commercial paper, which reflects its status as a vertically integrated electric utility company and its more than adequate liquidity profile. At times during the historical period under Enron control, PGE's cash balances exceeded $300 million. Such an unusually high cash balance was intended to ensure adequate liquidity during the then pending Enron bankruptcy proceedings. At June 30, 2007, PGE reported unrestricted cash of $42 million, having reverted to keeping substantially more modest cash balances, not unlike most other investment-grade rated investor-owned utilities. Since the end of 2006, PGE repaid $81 million of commercial paper, paid $28 million in common dividends, and funded short term working capital and other general needs.

At June 30, 2007, PGE had no commercial paper outstanding, reported no long-term debt due over the next 4 quarters, and including utilization of $13 million of letters of credit had $387 million of availability for additional borrowings and/or letters of credit under its $400 million unsecured bank credit facility. Although PGE has no long term debt maturing in 2008 or 2009, there are $142.4 million of pollution control bonds that, by the terms that apply, will be put back to PGE in 2009 as part of the expected remarketing of those bonds due in 2033. Aside from this situation, PGE's next material long-term debt maturity is $186 million due in 2010. Going forward, we expect that PGE will continue to maintain modest cash balances.

Meanwhile, PGE will continually face periodic spikes in working capital needs given variability in wholesale power market conditions and hydroelectric conditions from time to time. There is also a potential need to post collateral under a worst case outcome in litigation related to PGE's past recovery through rates of a return on its Trojan nuclear plant investment. The potential posting of collateral would likely be necessary before PGE could appeal any adverse ruling requiring a yet to be determined amount of customer refunds.

Against the backdrop of PGE's various capital needs, we believe the company will maintain its more than adequate liquidity over the next 4 quarters. This view reflects our expectations that PGE's cash flow from operations (exclusive of working capital changes) will be near $300 million over the next 4 quarters assuming reasonable regulatory support for impending utility investments and that PGE can also supplement its internally generated cash flow through issuance of commercial paper or direct borrowings under its $400 million committed five-year senior unsecured bank credit facility to meet short-term cash needs. In February 2006, the Federal Energy Regulatory Commission authorized that PGE could issue short-term debt up to a maximum $400 million outstanding at any given time during the two-year period February 8, 2006 through February 7, 2008. We do not expect PGE to come anywhere near the maximum allowed level, with peak short-term debt balances (i.e. commercial paper and direct borrowings) not likely to exceed $50 million over the next 4 quarters.

PGE's board authorized commercial paper program requires that it maintain unused bank credit equal to the amount of any commercial paper outstanding at a given point in time, effectively limiting its commercial paper issuance to $400 million. The timing of peak cash needs can vary in any given year depending upon weather and timing of spending associated with capital programs.

PGE's existing 5-year bank facility was recently extended to July 13, 2012 on essentially the same terms and conditions. The facility contains a covenant limiting the maximum debt level to 65% and does not contain a material adverse change provision beyond the original closing of the facility. We expect the company to adhere closely to its objective of maintaining a 50/50 mix of debt and common equity, which should leave it with ample headroom against the maximum allowed debt covenant. PGE's indebtedness to total capitalization, as calculated under the facility was 46.1% at June 30, 2007. Importantly, PGE's bank credit facility does not contain rating triggers that would cause acceleration, default, or puts, although it does contain rating sensitive pricing.

Rating Outlook

The stable rating outlook assumes that PGE's management will continue to be guided by their historically prudent financing strategies as the company moves ahead with its large capital program and, with the continuation of supportive regulation in Oregon, the company should be able to prospectively achieve financial results that support metrics alluded to in the financial metrics section above.

What Could Change the Rating - Up

Constructive outcomes in any future rate cases, which result in a reasonable opportunity for the utility to receive substantial and timely recovery of costs and to earn a return on the significant planned additions to rate base would be beneficial to PGE's credit quality and could contribute to an upgrade over the intermediate term. For example, an upgrade could occur if PGE demonstrates an ability to produce coverage by cash flow from operations (exclusive of the effects of changes in working capital) of interest and debt closer to 5x and the 22% - 25% range, respectively, on a sustainable basis. Also, satisfactory resolution of the various contingencies related to Trojan plant-related litigation, Senate Bill 408, and higher wholesale power costs incurred during the prolonged outage at the Boardman coal-fired plant during November 2005 through February 2006 would also be favorable credit developments.

What Could Change the Rating - Down

Any unexpectedly harsh decision by the OPUC in future rate proceedings that cause PGE to fall short of current financial expectations could result in a negative outlook or rating downgrade. This could include a weakening of the ratio of sustainable cash flow from operations (exclusive of working capital changes) to adjusted debt and adjusted interest falling below 20% and 4x, respectively, for an extended period.

Rating Factors

Portland General Electric Company

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

UE ___ / PGE / 1000
ZEPP

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Return on Equity

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Thomas M. Zepp

February 27, 2008

Table of Contents

I. Introduction and Summary

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

A. My name is Thomas M. Zepp. I am an economist and vice president of Utility Resources, Inc., Suite 250, 1500 Liberty Street, S.E., Salem, OR 97302.

Q. What is the subject of your testimony in this proceeding?

A. Portland General Electric Company ("PGE" or the "Company") asked me to estimate its required return on equity ("RROE"). I also call the RROE the "cost of equity" in this testimony. My study is based on data available to investors in November 2007.

Q. What are the results of your analysis?

A. The results of my analysis are provided in the table below:

Basis for Estimate	Estimated Cost of Equity for PGE
First DCF Analysis	11.4%
Second DCF Analysis	11.5%
Third DCF Analysis	10.7%
First Risk Premium Analysis	11.1% to 11.4%
Second Risk Premium Analysis	11.4%
Third Risk Premium Analysis	11.0% to 11.2%
Comparable Earned and Authorized ROEs	11.1% and 11.1%
Estimated Range of Equity Costs	10.7 to 11.5%
PGE Requested ROE	10.75%

Each of these estimates of PGE's RROE includes a 20 basis point risk adjustment to reflect PGE is more risky than the sample I use to determine benchmark cost of equity estimates.

Q. You have based your testimony on data available to investors in November 2007. Have recent developments in capital markets impacted the usefulness of your estimates of PGE's RROE?

A. No. The data I relied upon when I conducted my study in November 2007 were current at the time and match the time period of other data PGE relied upon in preparing its case. My estimates of the cost of equity made in November 2007 remain accurate and useful for several reasons. First, since November 2007, stock prices for many electric utility stocks have declined while expected future growth rates for electric utility stocks have increased. As a result, I would expect dividend yields today to be higher than in November 2007 and thus discounted cash flow ("DCF") equity cost estimates may be higher. Second, though short-term interest rates have dropped in response to investor concerns about recession and actions of the Federal Reserve, long-term rates expected in future years – which are the relevant rates for determination of costs of equity – have not declined as much. Also, as stock prices decrease, expected risk premiums ("RP") increase. Between November 30, 2007, and January 25, 2008, *Value Line* reported the expected appreciation potential for stocks increased from 55% to 70% in the next four years while interest rates had gone down, thus risk premiums have increased.

Q. How is your testimony organized?

A. In this section, I present the concept of a fair rate of return and a summary of my analysis.

In Section II, I discuss the risks of the electric utilities sample I rely upon to determine benchmark DCF equity cost estimates and compare the risks of the sample to risks faced by PGE. Based on the Commission's determination that PGE required a risk adjustment of 10 basis points in Order No. 07-015, my review of Ms. Stathis' and Mr. Hager's testimony and my own analysis of PGE's risks, I conclude that PGE requires a 20 basis point risk adjustment above the cost of equity for my benchmark electric utilities sample.

Section III develops my DCF equity cost estimates for a benchmark sample of 26 electric utilities based on three alternative DCF approaches. I also discuss reasons these DCF estimates are expected to understate required ROEs for the sample companies.

Section IV presents three RP analyses. Initially I explain why it is reasonable to expect equity cost risk premiums to vary inversely with interest rates and present different types of evidence that support such a conclusion. Subsequently, I present equity cost estimates based on three different risk premium approaches.

In Section V, I present a check on the reasonableness of my DCF and RP equity cost estimates based upon recent authorized and earned rates of return on equity ("ROEs") for the sample utilities.

Section VI provides a summary of my analysis, an estimated range in which PGE's cost of equity falls, and PGE's requested ROE.

Q. Have you prepared any tables to accompany your testimony?

A. Yes. I have prepared 16 tables that support my testimony, provided as PGE Exhibits 1001 through 1016.

Q. Please discuss what is meant by a fair rate of return.

A. A fair rate of return is achieved when a utility is authorized rates and rate adjustment mechanisms at levels where the expected return provides common stock investors a reasonable opportunity to earn the cost of common equity. Because operation expenses and interest on debt take precedence over payments to common stock holders, it is the common equity shareholder of the company who bears the greatest risk of receiving expected returns. In 1923, the U.S. Supreme Court set forth the following standards in the <u>Bluefield Waterworks</u> decision:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertaking which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. 262 U.S. 679,692-93 (1923).

In the <u>Hope Natural Gas Company</u> decision, issued in 1944, the U.S. Supreme Court stated the following regarding the return to owners of a company:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. 320 U.S. 591,603.

In 1989, in <u>Duquesne Light Co. v Barasch,</u> the U.S. Supreme Court also recognized an important economic concept. It found that regulatory commissions may need to adjust the risk premium element of the rate of return on equity to provide a fair return. It said:

> [W]hether a particular rate is "unjust" or "unreasonable" will depend to some extent on what is a fair rate of return given the risks under a particular rate setting system….488 U.S. 299,310.

Therefore, in determining an appropriate return, consideration must be given to the specific risks created by the nature and degree of regulation to which the utility is subject, in addition to examining general economic and financial data for utilities.

In Oregon, the legislature passed ORS 756.040 which puts into state law the principles the U.S. Supreme Court established in the <u>Hope</u> and <u>Bluefield</u> decisions.

The additional risk faced by PGE should be recognized when setting the fair rate of return for the Company. Ms. Stathis, Mr. Hager, and I explain unique additional risks of

PGE and why PGE requires a higher ROE than the electric utilities in the sample I use to determine guideline cost of equity estimates. In Order No. 07-015, the Commission recognized PGE's exposure to the wholesale market and concluded that PGE requires a risk adjustment of 10 basis points for this significant risk. I estimate that the risk identified by the Commission together with other risks discussed by Ms. Stathis, Mr. Hager, and I increase PGE's RROE by 20 basis points above the ROEs required by the benchmark samples of utilities I rely upon to conduct my ROE analyses.

Q. What is the crucial implication of the principles set out by the U.S. Supreme Court and in ORS 756.040 in the determination of a fair rate of return for PGE?

A. The crucial implication is whether the rates and rate adjustment mechanisms authorized for PGE by the Oregon PUC give PGE an opportunity to earn the rate of return investors could expect to earn if they invested in another utility of comparable risk.

Q. Are there other implications?

A. Yes. Other implications differ among bondholders, customers, and equity owners of PGE. From the perspective of bondholders, authorized rates need to be sufficient to assure current and prospective bondholders that PGE will have interest coverage comparable to other utilities having similar risk. Otherwise, the acceptance of PGE's bond will decline and borrowing costs will increase. An increase in bond costs would ultimately fall on the shoulders of ratepayers. This is especially important at this time when, as Ms. Stathis and Mr. Hager testify, PGE anticipates it will need to issue bonds.

From the perspective of equity owners, the principles require rates and rate adjustment mechanisms which provide a reasonable opportunity for PGE to earn a return that is commensurate with returns on investments in other enterprises having corresponding risks, sufficient to attract capital on reasonable terms and high enough to ensure confidence in the financial integrity of the firm. As I discuss further below, PGE is more risky than the electric utility samples I rely upon to determine benchmark estimates of the cost of equity and thus its required common equity return is higher.

From the perspective of customers, the RROE is another cost of service required by PGE so it can provide safe, reliable and adequate service now and in the future. Thus, the rates customers pay should provide a reasonable opportunity for PGE to earn that cost of equity. The fair rate of return on common equity is the cost of common equity and PGE's RROE.

Q. Please summarize your testimony.

A. My findings and recommendations are the following:

1. The cost of common equity faced by PGE is greater than the cost of common equity that faces a typical electric utility in the sample I use to determine guideline equity costs. PGE continues to require a risk adjustment of 10 basis points to compensate for its significant exposure to the wholesale market. PGE is also smaller and thus more risky than my benchmark sample. In addition, it is faced with a unique set of risks described by Ms. Stathis and Mr. Hager, including risk from SB 408, debt imputation, and rate-related litigation involving the closure of Trojan. These factors require an additional risk adjustment of at least 10 basis points, making PGE's cost of equity no less than 20 points above that of a typical electric utility.
2. The cost of common equity for the electric utility samples I use to determine guideline equity costs falls in a range of 10.5% to 11.3% at this time:

- Three DCF estimates for the electric utilities sample indicate the cost of equity falls in a range of 10.5% to 11.3%;
- Costs of equity derived from three risk premium analyses indicate the cost of equity for the benchmark electric utility sample falls in the range of 10.8% to 11.2%;
- Recently earned and authorized ROEs corroborate the reasonableness of these RP and DCF equity cost estimates.

3. I conclude that PGE's RROE falls in a range of 10.7% to 11.5% and thus the Company's requested ROE of 10.75% is conservative and I recommend it be adopted, as shown in PGE Exhibit 1016.

II. Risks of PGE and the Electric Utilities Sample

Q. As a preliminary matter, please discuss the sample of electric utilities you have used in your DCF analyses.

A. My DCF sample of electric utilities is composed of the 26 electric utilities listed in PGE Exhibit 1001. These electric utilities are all utilities listed by AUS Utility Reports in categories AUS calls "Electric Companies" and "Combination Electric & Gas Companies," which had investment grade bonds, had more than 50% of revenues derived from regulated electric revenues, paid a dividend, are not being acquired, and which either Reuters or the S&P Earnings Guide reports a consensus estimate of analysts' forecasts of growth. PGE Exhibit 1001 lists percentages of revenues from electric operations, S&P business profiles, *Value Line* estimates of betas, bond ratings, sizes, expected common equity ratios, and percentages of purchased power for the sample companies. It also displays averages of that information for the sample and comparable data for PGE.

Q. Please provide an overview of your discussion of risk.

A. Investors can choose to invest in many different types of assets with varying degrees of risk. Those investments might be in real estate, gold, collections of fine art, or financial assets. The financial assets run the gamut from relatively low risk assets such as Treasury securities and somewhat higher risk investment grade corporate bonds to relatively high-risk shares of common stocks. As the level of risk increases, investors require higher expected returns. Common stocks of utilities are generally more risky and thus require higher returns than investment grade bonds, which are secured debt instruments with fixed repayment terms. Operating expenses, interest on debt, and repayment of principal take precedence over payments to common stock holders, and thus it is the common equity shareholder of the utility who bears the greatest risk of receiving expected returns. Conceptually,

Required return for Common stock	=	Expected Return on a BBB bond	+	risk premium

BBB bonds are the lowest category of investment grade bonds.

Regulators generally set rates to give a utility a reasonable opportunity to recover its costs of service. One of those costs of service is the cost of common equity, the required return for the utility's common stock. The cost of equity is the expected return that is fair to both investors and customers. The return is fair to investors because it is equal to returns which investors could expect to earn if they invested in companies of comparable risk, is high enough to attract capital, and allows the utility to maintain its financial integrity. It is fair to customers because it is a cost of service and supports safe, reliable, and adequate service.

Q. Have the risks of electric utility stocks increased in recent years?

A. Yes. Professor Roger Morin is generally acknowledged to be an authority on issues related to electric utilities' costs of equity. His prior book, Regulatory Finance: Utilities' Cost of Capital, Public Utilities Reports, Inc. 1994, was often quoted in testimonies before regulatory commissions. In his new book, New Regulatory Finance, Public Utilities Reports, Inc., 2006, Dr. Morin provides the following chart that shows that equity risk premiums required by electric utilities have increased during the period 1987-2005.

New Regulatory Finance

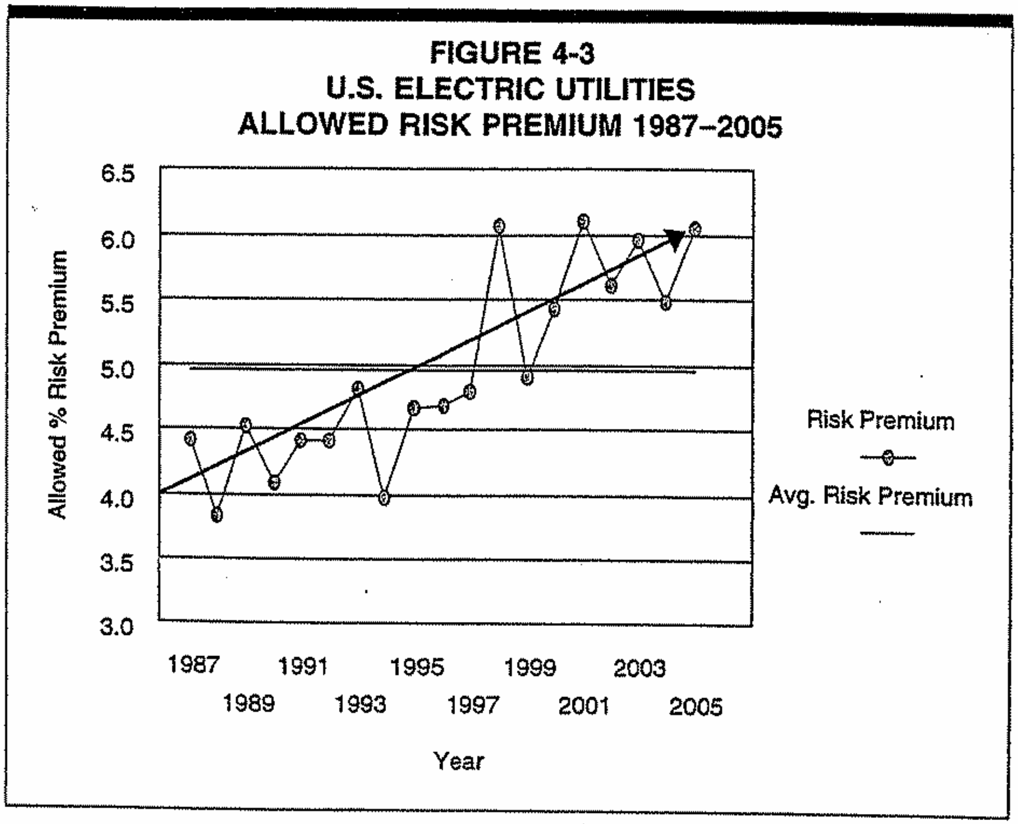


FIGURE 4-3
U.S. ELECTRIC UTILITIES
ALLOWED RISK PREMIUM 1987–2005

Q. Dr. Morin's chart shows electric utilities now require higher risk premiums than in the past. Is there other evidence that indicates risk of electric utilities has increased in the last few years?

A. Yes. Beta is the measure of risk in the traditional capital asset pricing model ("CAPM"). While this Commission has correctly concluded it is difficult to determine reliable equity costs with the CAPM, it is generally agreed that betas provide a measure of market risk. An average risk stock has a beta of 1.0 and lower risk companies have betas less than 1.0. PGE Exhibit 1002 provides evidence about beta risk estimated by *Value Line* in 2003 and 2007 that indicates this market measure of risk for the electric utilities sample has increased by 24% since 2003. As risk increases, the cost of equity increases. Not only has the average beta for the sample increased, but the beta for each and every one of the companies for which data are available has increased in the last four years. All else the same, higher betas for the electric utilities sample indicate these utilities now require higher equity returns than in 2003.

Q. What other data have you shown in PGE Exhibit 1002?

A. I have presented equity ratios for the sample utilities for 2003 and 2007.

Q. Is the increase in beta risk you discuss the result of electric utilities becoming more leveraged?

A. No. Just the opposite has occurred. PGE Exhibit 1002 shows common equity ratios for the guideline sample utilities have increased between 2003 and 2007. Everything else held equal, this reduction in leverage reduces risk. By reducing leverage, the electric utilities offset some – but not all – of the increase in business risk that has occurred between 2003 and 2007.

Q. In general, does an electric utility face more risk when it has to make additional investments?

A. Yes. Expected or unexpected requirements for additional capital spending means the utilities have to request rate increases more often and for larger percentage changes in order to maintain fair rates of return. Regulatory procedures are expensive, time consuming, increase uncertainty, and raise doubts in investors' minds that it is politically possible to request the required increases or that regulators will authorize high enough prices and/or price adjustment mechanisms to enable the utilities to earn fair rates of return. Investors may be concerned that regulators may delay the inclusion of new plant in rate base or part of the dollars invested or operating costs will not be authorized to be recovered. From an investor's point of view, it is the <u>potential</u> for such disallowances, delays or exclusion from consideration in setting new rates that increases risk. If additional investments were never required there would be no potential disallowances, delays or possible exclusions and investor concerns would never arise; thus risk would not increase. With the need for increased investments, uncertainty arises and the risk increases.

Q. Do electric utilities currently face risk from the need to make large new investments?

A. Yes. In recent discussions of electric utilities, *Value Line* has opined that a number of factors will force electric utilities to increase investments. *Value Line* noted that global warming, a growing demand for electricity, expanding population and increasing power use in equipment and consumer products are all stressing aged power grids and states that a number of electric utilities are currently spending billions of dollars to revamp their transmission and distribution networks to broaden supply access, boost capacity and enhance service reliability. Some of those investments are for so-called non-productive investments that are required to meet pollution control standards. Other investments are required because power demand is expected to grow faster than supply. (*Value Line*, p. 157, December 1, 2006).

In its September 28, 2007, discussion, *Value Line* said there has been increased demand for electricity and that even with improved cash flow, "available funds in most cases will be inadequate to cover the cost of new generating plants and transmission projects."

Q. Is the increase in demand important when considering the fair rate of return for electric utilities?

A. Yes, for two reasons. First, as explained above, increased demand increases risk, and thus the required rate of return increases. Second, plant investments made to meet increased demand growth should increase earning per share ("EPS") growth. This will occur as investment increases, rate base increases, and thus EPS increases at faster rates than occurred in the past. Given this difference in future and past EPS growth rates, it is critical that DCF equity costs be based on forward-looking estimates of growth and not past growth that is no longer relevant.

Q. Do analysts expect EPS growth to be higher in the future than it has been in the past?

A. Yes. PGE Exhibit 1003 compares analysts' forecasts of EPS growth for the DCF sample for 2004, 2005, 2006, and 2007. As the factors mentioned by *Value Line* have become recognized by the investment community, analysts' forecasts of growth have increased from 4.8% in 2004 to 5.7% in 2005, 6.4% in 2006, and 7.3% at the time I prepared this testimony.

Q. Do analysts expect PGE will also have higher future growth?

A. Yes, many do. After the January 2007 UE 180 Order for PGE, Standard & Poor's provided an assessment of PGE's bond rating and credit outlook. S&P specifically pointed to PGE's need to pursue a major resource acquisition program to reduce its dependence on purchased power. The mid-point of analysts' forecasts for PGE's EPS growth for PGE reported by Reuters and *Value Line* is 9.3%, which is above the 7.7% average of mid-points for the guideline sample, as shown in PGE Exhibit 1008.

Q. How does the risk faced by PGE compare to the risks of the electric utilities sample?

A. PGE is more risky than the sample. Ms. Stathis and Mr. Hager explain why exposure to SB 408, PGE's above-average purchased power requirements and expected capital investments increase PGE's risk. Exhibit 1001 shows PGE's purchased power requirements are higher than the sample average. Exhibit 1001 also shows PGE is more risky than the electric utilities sample because it is only 18% as large as the average electric utility in the benchmark sample. It is smaller than 20 of the 25 other electric utilities in that sample. For other measures of risk reported in PGE Exhibit 1001, PGE is no less risky than the utilities sample.

Q. Have this Commission and others specifically increased authorized ROEs to recognize the added risk of exposure to wholesale markets?

A. Yes. In Order No. 07-015, the Oregon Commission noted PGE had significant exposure to the wholesale market, particularly as compared to PacifiCorp, and increased PGE's authorized ROE by 10 basis points over PacifiCorp's to compensate for that risk exposure. The California PUC made a similar adjustment in December 2007. In California Decision 07-12-049, dated December 20, 2007, the California PUC stated that "based on informed judgment, a 50 basis point premium for debt leverage, debt equivalence and procurement risk should be added to the ROE base range for SCE." Edison International ("Edison") is the parent of SCE. The data in PGE Exhibit 1001 show Edison is expected to have the same leverage as PGE, and PGE and Edison both have above-average percentages of purchased power (and thus above-average debt equivalence), though Edison has a somewhat higher percentage of purchased power. Based on a consideration of debt equivalence and procurement risk alone, this evidence indicates that, all else equal, the risk adjustment for PGE should be higher than the 10 basis points found reasonable in Order No. 07-015. All else, however, is not equal. PGE is more risky because it is smaller than Edison, and Edison does not have risk related to SB 408 and other risks discussed by Ms. Stathis and Mr. Hager.

Q. Why does PGE's size matter?

A. Academic studies have addressed the issue of company size and risk and have found that, in general, smaller firms are more risky. The seminal version of CAPM, developed in the mid-1960s, relied upon only beta as the measure of risk. Eugene Fama and Kenneth French ("The Capital Asset Pricing Model: Theory and Evidence," *Journal of Economic Perspectives*, Volume 18, No. 3, Summer 2004 pp. 25-46) provide evidence that questions the usefulness of the simple CAPM and explain that other variables such as company size and various price ratios add to the explanation of stock returns. This problem of choosing the "correct version" of CAPM is, of course, one of the problems with using CAPM to determine equity costs for utilities. But notwithstanding which CAPM version is the correct one, Fama and French did find that company size as well as beta and another factor help explain how investors price common stocks.

Ibbotson Associates[1] also examined this issue for a number of years and found that smaller firms require higher and higher returns as size becomes smaller and smaller. (Morningstar, *2007 SBBI Yearbook Valuation Edition*, Chapter 7). I also published an article, "Utility Stocks and the Size Effect – Revisited," *The Quarterly Review of Economics and Finance*, Vol. 43, Issue 3, Autumn 2003, pp. 578-582, which showed smaller utilities are more risky than larger utilities. Combined, this information shows there is no "bright line" that separates smaller, higher risk utilities from larger, lower risk utilities, but that risk and required ROEs increase as utilities are smaller.

Q. Have you determined a specific risk adjustment to compensate PGE for being smaller than the sample you rely upon in PGE Exhibit 1001 to conduct your DCF analyses?

A. No. Morningstar divides companies into ten deciles and estimates betas and size premiums with different methods. The first decile contains the largest companies. PGE's size places it in the sixth decile while the sample average falls in the second decile. Based on the estimates reported by Morningstar in 2007, a typical company in the sixth decile has a larger

[1] Ibbotson Associates was recently purchased by Morningstar and is referred to as Morningstar hereafter.

beta than a typical company in the second decile and requires a size risk premium no less than 32 basis points higher than the size risk premium required by a company in the second decile[2]. While I do not determine a specific risk adder for size, I do take this evidence into account when determining the risk premium above the equity costs estimates made for the benchmark sample.

Q. What is your recommended risk adjustment for PGE?

A. The Commission has previously determined at page 47 of Order No. 07-015 that PGE requires a risk premium of 10 basis points to compensate for its significant exposure to the wholesale market. Ms. Stathis and Mr. Hager have explained that this risk persists in the test period. PGE also faces other risks discussed by Ms. Statis and Mr. Hager and it is more risky because the Company is smaller than the average company in the sample of utilities use to determine benchmark equity costs. Taking into account PGE's exposure to these various risks, I conclude PGE requires an equity cost risk adjustment above the cost of equity estimates for the electric utilities sample of no less than 20 basis points at this time.

[2] Morningstar, SBBI Valuation Edition 2007 Yearbook, Chapter 7 and Tables 7-2, 7-10, and 7-11.

III. DCF Equity Cost Estimates

Q. Do you have preliminary comments related to the use of the DCF model to determine equity cost estimates?

A. Yes. Given the weight the Commission has given to the DCF model in recent Oregon decisions, I begin my RROE study with my DCF estimates. However, I strongly recommend the Commission consider several versions of the DCF model and other useful information to determine a fair ROE for PGE. The DCF model depends crucially on assumptions about constant or multi-period growth rates. Not only are there unavoidable difficulties with estimating growth rates but also investors may consider information and financial models other than the DCF model to price stocks. Other methods assume investors make decisions in different ways and thus it is appropriate to make different abstractions to model investor behavior. There are no guarantees that any particular method is superior to others. It follows then that other methodologies should be considered.

At a minimum, other financial models and the data regarding authorized and earned ROEs in PGE Exhibit 1004 should be used as a check on the specific DCF assumptions and methods being employed. Several methods and large samples of comparable risk companies should be relied upon to make those estimates whenever possible. If the equity costs produced with DCF methods and assumptions chosen by an analyst are significantly different than equity costs resulting from application of other financial models and checks on the reasonableness of the results made by examination of other authorized and earned ROEs, those DCF results should be seriously questioned or rejected.

Q. Please summarize your DCF estimates.

A. My DCF estimates are provided in PGE Exhibits 1007, 1009, and 1010. The estimates presented in PGE Exhibit 1007 are based on the constant growth DCF model and forward-looking estimates of growth. PGE Exhibit 1007 relies on an average of analysts' forecasts of growth reported by four institutions and finds the benchmark cost of equity is 11.2% and thus the indicated cost of equity for PGE is 11.4% at this time. PGE Exhibit 1009 relies on concepts the Federal Energy Regulatory Commission ("FERC") used to estimate equity costs with its multi-period DCF growth model, a forecast of GDP growth and a range of growth forecasts reported by Reuters and *Value Line*. This method finds the estimated DCF equity cost for the sample is 11.3% and thus 11.5% for PGE. PGE Exhibit 1001 is a multi-stage analysis which assumes three different stages of growth are expected by investors and that ultimately all dividends per share ("DPS") will grow at the same rate as growth in the economy as a whole. With this approach, the indicated average DCF equity cost estimate is 10.5% for the sample and 10.7% for PGE.

Q. Please explain the DCF method of estimating the cost of equity.

A. The constant growth DCF model computes the cost of equity as the sum of an expected dividend yield ("D_1/P_0") and expected dividend growth ("g"). The expected dividend yield is computed as the ratio of next period's expected dividend ("D_1") divided by the current stock price ("P_0"). Generally, the constant growth model is computed with formula (1) or (2).

(1) Equity Cost = $D_0/P_0 \times (1 + g) + g$

(2) Equity Cost = $D_1/P_0 + g$

where D_0/P_0 is the current dividend yield and D_1/P_0 is found by increasing the current yield by the growth rate or relying on a forecast of D_1. The constant growth DCF model and multistage DCF models are derived from the valuation model shown in equation 3 below:

(3) $$P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + D_\infty/(1+k)^\infty,$$

where k is the cost of equity; P_0 is the current stock price, D_1, D_2, . . . D_∞ are cash flows expected to be received in periods 1, 2, . . . ∞, respectively. Equation 3 is equivalent to equation 4 when it is expected that the stock will be sold at price P_n at the end of period n:

(4) $$P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + (D+P)_n/(1+k)^n.$$

In the case of the constant growth DCF mode, DPS, EPS, stock prices and book values are all assumed to grow at the same rate in every future period. In multistage DCF models, after an initial period (or periods) has passed, future DPS, EPS, book values and stock prices are assumed to grow at faster or slower rates than in the initial stage (or stages).

Q. How did you compute the dividend yields?

A. My dividend yield estimates are denoted as D_1/P_0 in equation (2) above. My dividend yields are averages of the highest and lowest dividend yields which occurred during the period July 1, 2007, to September 30, 2007. My estimates of D_1 are *Value Line's* estimated dividends for the next 12 months reported by *Value Line* in its August 31, 2007, Summary and Index, which I have adjusted to compensate for the time value of money.

Q. Why have you adjusted the values for D_1 for the time value of money?

A. This adjustment is required because equation (3) above assumes dividends are paid once a year but investors receive dividend payments on a quarterly basis. If a utility pays a dividend of $100 per year, investors would prefer to be paid $25 every quarter instead of $100 at the end of the year. Prices investors pay for utility stocks reflect the benefit investors receive by utilities paying dividends every quarter but equation (3) assumes the $100 is paid only once a year. The quarterly DCF model adjusts the dividend upward by just enough to offset the time value of receiving the $100 in four quarterly installments of $25 each.

The values adopted for D_1 must also reflect the fact that DPS are expected to increase over time since all of the utilities in the sample are projected to have growth in the future. I recognize that potential positive growth by adopting *Value Line's* forecasts of dividends for the next 12 months. Other methods could be adopted to recognize the near-term growth in DPS, but I have used this conservative approach to minimize controversy. A general discussion of the various approaches that could be taken is provided in Roger Morin, New Regulatory Finance, pages 343-349.

Q. How did you estimate growth rates?

A. Growth rates used with the DCF model should be based on the best available forecasts of future growth. A number of investor services report consensus averages of analysts' forecasts of growth. Currently, Reuters reports the most comprehensive information about what analysts expect future growth to be. Reuters reports not only the mean (consensus) estimate of future EPS growth, but also the number of analysts' forecasts included in the average, the highest growth forecast, the lowest growth forecast and the standard deviation in the reported forecasts. The S&P Earnings Guide provides the number of analysts providing forecasts as well as the average consensus growth rate. Zacks and Thomson First Call also report analysts' forecasts of growth, but the information provided by those financial institutions is not as exhaustive as the data provided by Reuters and S&P. In order to be included in my benchmark sample, I required that there be at least one analyst's forecast reported by either Reuters or the S&P Earnings Guide. PGE Exhibit 1006 provides a list of the available analysts' forecasts reported for the sample utilities by the four institutions. Column (i) of PGE Exhibit 1006 reports averages of the available analysts' forecasts. In the case of Empire District, there were only two analyses. Taken together, the average of the analysts' forecasts provided by all four of the institutions is 7.5% at this time. This average is slightly higher than the 7.3% average determined in PGE Exhibit 1003 because only 24 of the 26 utilities in the sample were included in the 2007 data used to prepare PGE Exhibit 1003. The complete average of analysts' forecasts reported by the S&P Earnings Guide is 7.4%. See PGE Exhibit 1006.

I also determined growth rates from data reported by *Value Line,* which is discussed below.

Q. Is a 7.5% growth rate in line with growth rates parties presented in UE 180?

A. Yes. Analysts now expect much more rapid growth for electric utilities than they did just two or three years ago. I do not have historical information for Zacks, Reuters or First Call, but do have copies of the S&P Earning Guide for December 2004, December 2005, and December 2006 as well as October 2007. PGE Exhibit 1003 shows that the current average of analysts' forecasts of growth reported by the S&P Earnings Guide is 160 basis points higher than in December 2005 and 250 basis points higher than it was three years ago. Those average forecasts of growth from the earlier periods are in line with growth rates presented in UE 180.

Q. Why has expected growth increased during the last several years?

A. There are a number of reasons. Some of those reasons have already been discussed above. Electric utilities must invest more in their systems to replace aging infrastructure and old power plants and to provide for more capacity, to address more stringent pollution requirements and to meet increased future demand. As those investments are made, rate bases increase and future EPS will grow more rapidly than in the past. At the same time, as more investments must be made, risk and the cost of equity both increase.

Q. Did you also consider *Value Line* forecasts of future growth?

A. Yes. I rely on a range of forecasted EPS growth rates provided by Reuters and *Value Line* to prepare my multi-stage DCF equity cost estimates. These ranges of growth rates are reported in PGE Exhibit 1008 and the DCF analyses are provided in PGE Exhibits 1009 and 1010. I determine these DCF equity cost estimates in separate analyses because many of the *Value Line* forecasts of future growth do not fall within the ranges of forecasts reported by Reuters.

Q. Please explain your second DCF analysis.

A. My second DCF analysis is a two-stage DCF analysis based on concepts relied upon by the FERC and fully discussed in *Southern California Edison Company*, Opinion No. 445,92 F.E.R.C. 61,070 (2000) and in Opinion 396-B, *Northwest Pipeline Company*, 79 F.E.R.C. 61,309 (1997). The concepts I rely upon are as follows:

- Adopt averages of high equity cost estimates and low equity cost estimates to determine a range of cost of equity estimates.
- Determine each equity cost with a two-stage DCF analysis in which the initial growth rate is given a weight of two-thirds and the terminal growth rate is given a weight of one-third.
- Adopt the FERC method of relying on EPS growth forecasts to determine initial growth rates.

- Adopt the FERC method of relying on a GDP forecast as the terminal growth rate estimate.
- Consistent with the FERC approach, eliminate from consideration any equity cost estimate that is not greater than 40 basis points above the cost of A-rated bonds.

In making each high (low) equity cost estimates, I rely upon the highest (lowest) analyst's forecast in the range of growth rates reported in PGE Exhibit 1008.

Q. How did you estimate GDP growth for the second stage of this two-stage analysis?

A. When FERC gives a weight of one-third to GDP growth it is assumed that the second stage will not start for many years into the future and therefore investors relying on the method would focus primarily on expected long-term GDP growth, not GDP growth expected in the next few years. Such estimates of long-term GDP growth would consider not only forecasts of future GDP growth but GDP growth that has occurred during long periods in the past.

Initially, I considered (a) past annual average GDP growth of 6.8% which Staff of the Arizona Corporation Commission relies to determine growth for the second stage of its multi-stage DCF analysis (Direct Testimony for ACC Staff of Steven P. Irvine, in Docket No. W-01303A-07-0209 (Arizona-American Water Company), dated October 15, 2007, page 26), (b) GDP growth of 6.757% reported by PGE in UE 179, and (c) post long-term real GDP growth of 3.3% reported by OPUC Staff in UE 180 Staff/800 Morgan/20. I also considered consensus estimates of GDP growth which can be derived from Quarterly Forecasts made by *Value Line* and semi-annual consensus forecasts reported by Blue Chip.

To make my forecast of future long-term GDP growth, I took what I believe is a conservative approach and assumed that investors would be aware of the long-term real

GDP growth of 3.3% reported by Staff and assume such real growth will occur again in the future. *Value Line* forecasts future inflation for the CPI-all urban consumers' index and the PPI-finished goods index will be 2.5% for the period 2011 (most distant period in the future). These forecasts fall within a range of forecasts reported by Blue Chip in June 2007. Combining the 3.3% real GDP growth with a long-term inflation forecast of 2.5%, the indicated future GDP growth rate is 5.8%, which is the value I have used in my analysis. This is a very conservative forecast of GDP growth which would be expected by investors given the actual annual GDP growth has averaged 6.8% in the past.

Q. What are the results of your two-stage DCF analysis?

A. The results are reported in PGE Exhibit 1009. The average of the high equity cost estimates is 13.3% and the average of low equity cost estimates is 9.2%. The mid-point of the wide equity cost range is 11.3% after applying FERC's standard removal of estimated equity costs less than 40 basis points above the cost of A-rated bonds. Given recent spreads between A-rated and Baa-rated bonds, the FERC criteria would require elimination of any equity cost estimate that is 25-30 basis points above the cost of Baa bonds. Such a principle is appropriate for any equity cost approach because all credible estimates of the cost of equity for utilities must be higher than the yield on investment grade bonds. PGE Exhibit 1011 shows the average of forecasts of Baa rates made by Global Insight and Blue Chip for 2009 is 7.06% and thus I did not include the low equity cost forecast for American Electric Power and IDACORP in my average of low equity cost estimates.

Q. Why is the preliminary range of equity cost estimates so wide?

A. It is this wide because it is based on the highest and lowest forecasts of growth from PGE Exhibit 1008, not consensus estimates of growth. While it is generally not appropriate to base an equity cost estimate on either of those extreme values, the FERC approach recognizes the mid-point of that range provides a reasonable equity cost estimate. Based on the range of *Value Line* and Reuters EPS growth forecasts, the indicate average cost of equity for the sample is 11.3% and the indicated cost of equity for PGE is 11.5%.

Q. Please describe your third DCF analysis.

A. My third DCF analysis is developed in PGE Exhibit 1010. This analysis determines the cost of equity by finding the internal rate of return that is consistent with different growth rates in three stages. Initially it is assumed that the prices paid ("P_{2007}") and dividends ("D_{2008}") during the next 12 months are those reported by *Value Line* at August 31, 2007, in its Summary & Index. Growth rates adopted for the first stage (for 2009-2013, the next five years) are the mid-points of the ranges of EPS growth rates reported in PGE Exhibit 1008. I have assumed – as does the FERC – that EPS growth is the critical concern of knowledgeable investors who realize that earnings enable the utility to increase dividends. PGE Exhibit 1010 reports the first and last forecasted dividend for this period (D_{2009} and D_{2013}) for each utility.

The second stage is a transition stage in which growth in the first stage is assumed to gradually increase (or decrease) toward a terminal growth rate over a period of ten years (2014 to 2023). PGE Exhibit 1010 reports the first and last two forecasted cash distributions for this period (D_{2014}, D_{2022} and $P+D_{2023}$) for each utility. The terminal growth rate is assumed to be GDP growth of 5.8% which I discussed above. In 2023 it is also assumed that the stocks are sold and the prices paid for those stocks anticipate DPS growth will equal GDP growth in all future periods. The selling price for the respective stocks reflects GDP growth during that final (third) stage.

Q. What is your average equity cost estimate based on this third DCF approach?

A. This analysis indicates the average cost of equity estimates for the benchmark sample companies is 10.5% and thus the indicated cost of equity for PGE is 10.7%.

Q. Do you have any general concerns with determining RROEs with equity cost estimates made with the DCF model?

A. Yes. Kolbe, Vilbert, and Villadsen published an article in 2005 which addresses the mismatch of capital structure considered by investors when they buy utility stocks and the capital structure used in an original cost jurisdiction like Oregon (A. Lawrence Kolbe, Michael J. Vilbert, and Bente Villadsen, "Business 7 Money – Measuring Return on Equity Correctly" www.fortnightly.com/pubs/4572.cfm, August 2005). Kolbe, Vilbert, and Villadsen's argument is logical and intuitive. It is that investors buy common stocks at market prices above book values and thus the equity ratio of concern to them is higher than the more leveraged equity ratio used by regulators to set rates.

Currently electric utilities have book equity ratios (which are used in ratemaking) of approximately 50%. For my example, I assume the market to book ratio of concern to investors is 1.7. Based on simple arithmetic, these data imply the market equity ration is 63% and thus the market debt ratio is 37% (assuming no preferred stock and book costs of debt are the same as market values of debt to keep the analysis simple). Kolbe, et. al. report that the financial literature now concludes the required after-tax ROR does not change with differences in leverage for a reasonable range of equity ratios. Assuming a debt cost of 7% and an equity cost derived from market data of 10.5%, we have the following:

	Market Capitalization Ratios	**Cost**	**Weighted Cost**
Debt	37%	7.00%	2.59%
Equity	63%	10.50%	6.61%
Total			**9.20%**

Kolbe, et. al. say the embedded cost of debt (I have assumed is 7%) should be used in this analysis.

When regulators set rates, the original cost of book equity is used in the capital structure for ratemaking and, after recognizing the increase in leverage, the indicated cost of equity increases to "K":

	Capitalization Ratios	**Cost**	**Weighted Cost**
Debt	50%	7.00%	3.50%
Equity	50%	K	5.70%
Total			9.20%

Solving for K, the indicated cost of equity for ratemaking purposes is 11.4%, not 10.5%. Kolbe, Vilbert, and Villadsen conclude:

> Differences between the market-value capital structures of the sample companies and the capital structure used to set rates can be large. If so, there will be equally large differences in the amount of financial risk – hence, the costs of equity at the different capital structures. Failure to take these differences into account is likely to lead to allowed rates of return on equity that are below the costs of equity that utility shareholders actually require. ("Business & Money – Measuring Return on Equity Correctly" www.fornightly.com/pubs/4572.cfm, August 2005, page 3)

Q. Have you adjusted your DCF equity cost estimates to reflect this analysis?

A. No, I have not. I have presented it to explain why DCF models could produce cost of equity estimates that are lower than equity costs indicated by other models.

IV. RP Equity Cost Estimates

Q. Please turn to your risk premium equity cost estimates. Please summarize the equity cost estimates you make with this approach.

A. I make three risk premium ("RP") equity cost estimates that indicate the cost of equity for PGE falls in a range or 11.1% to 11.4%.

Q. In general, how is an equity cost determined with a risk premium approach?

A. A risk premium equity cost is made by first determining what the relationship has been between equity costs and interest rates over a period of time. Then that relationship is combined with a current forecast of the interest rate to predict the current cost of equity. Generally such equity cost estimates depend on different assumptions about how investors price stocks than are assumed when making DCF equity cost estimates.

Q. Are risk premium approaches widely used in the financial community?

A. Yes.

Q. Please compare interest rates in the past to interest rates expected in 2009.

A. In 2003, annual averages of various interest rates dropped to the lowest levels that have occurred in close to forty years. From 1964 to 2002, annual average yields on 10-year Treasury securities, for example, ranged from 4.19% to 13.92%. And, for the 10-year period ending in 2002, the annual averages of 10-year Treasury rates ranged from 4.61% to 7.09%. In 2003, that annual average was only 4.01%. For comparison, in 2006 the annual average for 10-year Treasuries was 4.80%. Currently, monthly averages of the 10-year Treasury have declined from 5.1% in June 2007 down to 4.15% in November 2007 but are expected to bounce back up in 2009, the year PGE's new rates are expected to be put in place. PGE Exhibit 1011 reports forecasts made by Blue Chip and Global Insights for 10-

year Treasury security rates in 2009. Global Insight and Blue Chip forecast interest rates are expected to be somewhat higher in 2009 than they are today. PGE Exhibit 1011 also reports forecasts of Baa rates and 30-year Treasury rates for 2009 that are somewhat higher than those interest rates were at the time I prepared this testimony. My analyses below recognize that although interest rates are expected to increase by 2009, the rates are still expected to be lower than in many years in the past.

Q. Do you expect risk premiums to vary inversely with interest rates?

A. Yes. There is a theoretical reason and many sources of empirical data to support equity cost risk premiums increasing as interest rates decrease.

Q. Why is this inverse relationship between interest rates and risk premiums important at this time?

A. It is important because interest rates in 2009 are expected to be lower than historical averages and thus risk premiums in 2009 are expected to be higher. While interest rates have increased somewhat since 2003, the level of interest rates in November 2007 and expected in 2009 are still lower than interest rates were during periods used to determine historical relationships between interest rates and equity costs (and, thus, risk premiums). As a result, risk premiums today are expected to be higher than in the past.

Q. What is the theoretical reason risk premiums are expected to increase when interest rates decrease?

A. The theoretical support is found in Myron Gordon and Paul Halpern's article, "Bond Share Yield Spreads Under Uncertain Inflation," American Economic Review, Vol. 66, No. 4, September 1976, pp. 559-565. In that article Gordon and Halpern explained that as investors expect higher uncertain inflation, interest rates would increase to reflect greater uncertainty and higher expected inflation, but costs of equity would not increase as much because stocks – but not bonds – provide a hedge against inflation. This common sense theory provides a strong conceptual basis for the empirical analyses discussed and applied below. I note that Gordon and Halpern concluded their article with empirical support for the theory based on differences in bond costs and equity costs for electric utilities. They found that as Aaa bond rates increased, risk premiums for electric utilities decreased.

Q. Have other authors found an inverse relationship between risk premiums and interest rates?

A. Yes. Harris and Marston, "Estimating Shareholders Risk Premia Using Analysts' Growth Rates, "Financial Management," Summer 1992 found an inverse relationship as did Roger Morin in a study reported in chapter 4 of his 2006 book New Regulatory Finance.

Q. Has OPUC Staff addressed this issue?

A. Yes. In UT 85, Phil Nyegaard stated "Theory suggests that relatively high inflation narrows the risk spread between stocks and bonds, and that relatively low inflation widens that spread." Based on this theory and data from Ibbotson and Sinquefield, Mr. Nyegaard determined the risk premium for the stock market as a whole was expected to be above the long-term average because investors expected inflation (and future bond rates) to be lower than the long-term average at the time he prepared that testimony. (Staff/3 Nyegaard/14, UE 85, January 1989.).

Q. Please turn to your first risk premium analysis.

A. The first approach I use is based on a method routinely used by the Department of Ratepayer Advocates of the California PUC to determine equity costs for utilities (see Division of Ratepayer Advocates, California PUC Report on the Cost of Capital, San Jose Water June

2006, Application 065-02-014). This method relies on annual averages of past recorded book returns on equity for a sample of utilities as proxies for costs of equity. It assumes that regulators adopt rates and rate adjustment mechanisms that give utilities reasonable opportunities to earn their RROEs and thus – though each individual utility may earn more or less its RROE in a given year – the average of the sample ROEs provides a useful proxy for the average cost of equity for the sample.

Q. How did you implement this method in this case?

A. To make this analysis, I adopted averages of earned ROEs for the 14 utilities adopted by the Oregon PUC Staff in UE 180 as the proxies for annual average equity costs for the 10 year period from 1997 to 2006. PGE did not support Staff's sample group in UE 180 and in Order 07-015, the Commission found estimates of the cost of equity made with data for the sample were "uniformly low." Using the UE 180 Staff sample group for a risk premium equity cost estimate is thus a means to provide a conservative and relatively non-controversial estimate of PGE's cost of equity. To prepare this analysis, I used data for annual earnings per share from 1997 to 2006 and beginning and ending book values for 1996 to 2006 from *Value Line* and OPUC Staff work papers in UE 180.

Q. What are the results of this first RP analysis?

A. This risk premium analysis indicates the estimated 2009 average cost of equity for the electric utility sample adopted by the Staff in UE 180 falls in a range of 10.9% to 11.2%. As expected from the evidence I presented above, the estimated average risk premium in the most recent 5-year period is somewhat higher than the average range for the full 10-year period. This result is expected because average interest rates were lower in 2002-2006 than in 1997-2006. My analysis is reported in PGE Exhibit 1012. Forecasts of interest rates expected in 2009 are reported in PGE Exhibit 1011.

Q. What are the results of your second RP analysis?

A. My second approach computes the risk premium as the average of realized market return premiums over a period of time. This analysis indicates the cost of equity for a typical electric utility is 11.2% and thus the indicated cost of equity for PGE is 11.4%.

Q. Please discuss this second risk premium analysis.

A. The second risk premium analysis is a market approach reported in PGE Exhibit 1013. It is based on an average of differences between annual total realized returns for Moody's index of electric utilities and yields on Baa bonds at the beginning of the respective years. This approach recognizes that the annual actual risk premium in any particular year will probably not equal the required risk premium but that, over a long period of time, the average of those annual actual risk premiums provides a good estimate of the average risk premium which was required during that period.

Initially, I computed two preliminary average risk premiums. The first preliminary risk premium is for the period ending in the year 2000 when Moody's stopped updating this index. The second preliminary estimate was for the full period ending in 2006 which is based on my update of the Moody's sample data for 2001 to 2006. Data for 2007 were not available when data for this study were complied. I report the results for both the original period and the updated period but rely upon the updated data to determined this second RP estimate of the cost of equity.

The preliminary analyses determine average risk premiums and thus do not incorporate the evidence I presented above that risk premiums vary inversely with interest rates. Since a

Baa rate of 7.06% expected in 2009 is lower than the average of Baa rates of 8.0% for the period 1950 to 2005 and lower than the average interest rate of 8.1% during the period of the original study, the future risk premium is expected to be higher in 2009 than the simple average RP based on past data. To incorporate this additional information, I adjusted upward the risk premium estimates based on the bottom of the range of changes in risk premiums implies by the California PUC orders I discussed above. Based on these estimates, the benchmark equity cost estimate is 11.2% and the indicated cost of equity for PGE is 11.4%.

Q. What is the conceptual basis for your third RP analysis?

A. The third approach is a more sophisticated version of a method adopted by Staff of the FERC to implement its risk premium approach in Docket No. ER93-465-000 that recognizes risk premiums increase (decrease) as interest rates decrease (increase). My third RP method is similar to a risk premium estimation approach Dr. Roger Morin presented in Chapter 4 of his 2006 book, New Regulatory Finance.

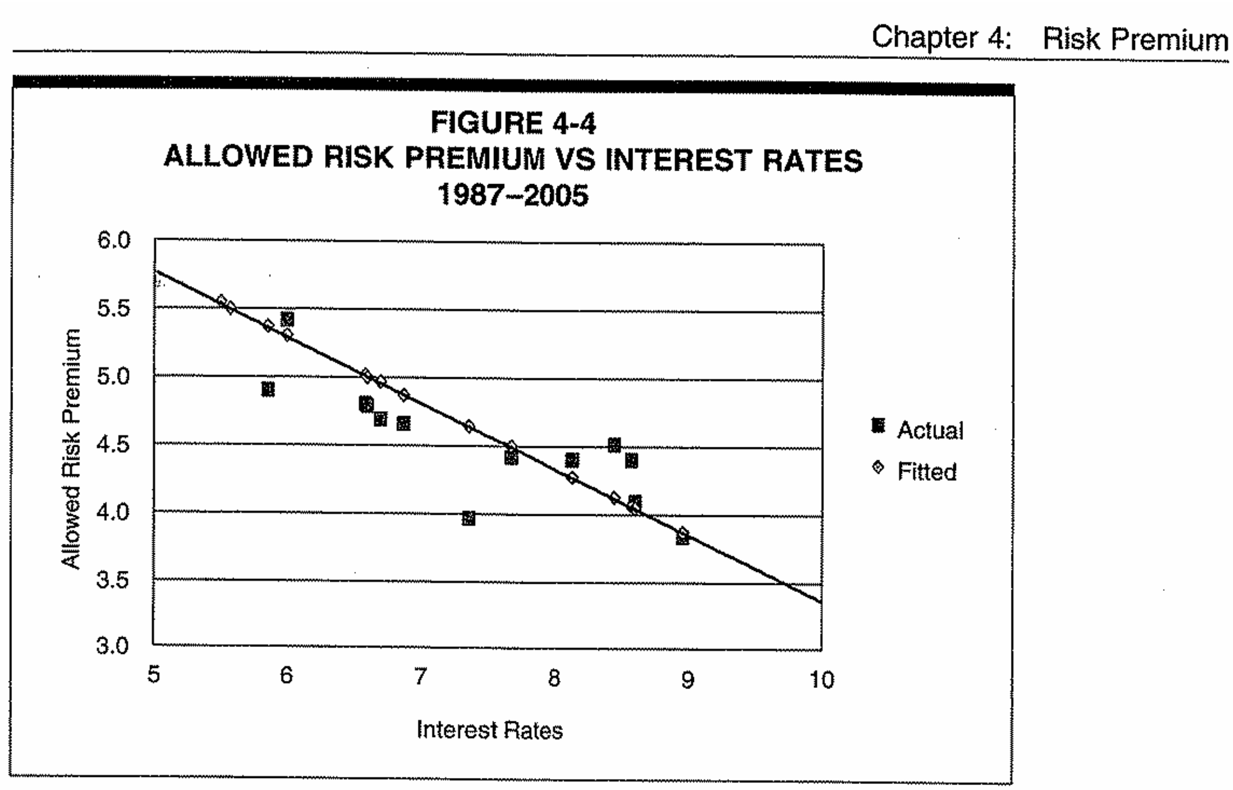
Dr. Morin reports that risk premium equity cost estimates have been used in regulatory proceeding for many years and are widely used by analysts, investors and expert witnesses. He notes that the RP approach to estimating the cost of equity derives its usefulness from the simple fact that while equity return requirements cannot be readily quantified at any given time, the returns on bonds can. Thus, if the risk premium is known, it can be used to produce a useful estimate of the cost of equity.

One of the techniques Dr. Morin explains can be used to determine the "cost of common equity consists of examining the risk premiums implied in returns on equity allowed by regulatory commissions for utilities over some past period relative to the contemporaneous level of the long-term Treasury bond yield," (New Regulatory Finance, page 123). Professor Morin reports the following statistical relationship between risk premiums (RP) and interest rates (YIELD) for the period 1987 to 2005 for electric utilities:

$$RP = 8.2049 - 0.4833 \times YIELD \quad R^2 = 0.81$$

$$(t= -8.4)$$

where allowed equity returns reported by Regulatory Research Associates are adopted as the proxies for equity costs. To obtain a cost of equity estimate, Dr. Morin inserts a current or projected Treasury bond yield in his estimated equation. He further explains, "Figure 4-4 shows the clear inverse relationship between the allowed risk premium and interest rates revealed in past common equity decisions." The risk premium method presented by Dr. Morin is discussed in Section 4.5 of his new book and is shown graphically in Figure 4-4 reproduced below:



The risk premiums reported in the figure are the costs of equity implied by consideration of authorized ROEs relative to contemporaneous yields on long-term Treasury bonds.

Q. Is your third RP approach consistent with the analysis Dr. Morin presented in his new book?

A. Yes. My third RP analysis is consistent with the academic research an analysis presented by Dr. Morin in New Regulatory Finance, but relies on a larger sample of 456 individual actual litigated decisions in stead of annual averages of those decisions used in Dr. Morin's analysis. I have also based my analysis on 30-year Treasury rates six months prior to the dates decisions were issued by the commissions to recognize the practical constraints of regulatory proceedings in which DCF, RP and other financial models used to determine authorized ROEs are based on data available several months prior to the issue of order.

Q. What specific studies did you conduct?

A. I conducted analyses with data for a longer period (1985 to 2006) as well as a shorter more recent period (1990 to 2006). My longer period is slightly longer than the 1987 to 2005 period Dr. Morin used in his analysis. The results for the longer period are shown in PGE Exhibit 1014 and the results for the shorter period are in PGE Exhibit 1015. Taken together this risk premium approach indicates a typical electric utility can expect to face a cost of equity that falls in a range of 10.8% to 11.0% in 2009. As PGE is more risky than the typical electric utility, once a 20 basis point risk adjustment for PGE is recognized, this model indicated PGE's cost of equity is expected to fall in a range of 11.0% to 11.2% in 2009. Equity cost estimates for PGE that are made with my modification of the Morin RP method fall within their range of equity costs made with the other two RP approaches and thus corroborate those other analyses.

Q. Are you aware of another method that has been used to determine the risk premium equity cost estimates?

A. Yes, I am aware of the method presented by Harris, Marston, Mishra and O'Brien, "ExAnte Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66). In that approach annual estimates of equity costs and annual risk premiums are determined with the DCF model and then averaged to get a risk premium estimate which can be combined with appropriate estimates of current interest rates to estimate a future equity cost. I have not used that method in this case because it relies on the DCF model and I have already presented such equity costs in Section III.

V. Authorized and Earned ROEs

Q. Have you made any checks on the reasonableness of your DCF and RP equity cost estimates?

A. Yes. At page 47 of Order No. 07-015 (the UE 180 case), the Commission stated it would not rely upon rates authorized in other jurisdictions to determine ROEs, but will use those decision to gauge the reasonableness of its decision. I present PGE Exhibit 1004 to provide such a gauge.

Q. Does PGE Exhibit 1004 provide perspective about what is a fair ROE for PGE at this time?

A. Yes. As I noted above, the U.S. Supreme Court's decisions in the 1923 Bluefield Waterworks case and 1944 Hope Natural Gas Company case, as well as ORS 756.040 set forth three standards for a fair ROE. In effect, Oregon and the U.S. Supreme Court require the Commission to determine rates and rate adjustment mechanisms for PGE that allow the Company to have a fair chance to earn its opportunity cost of capital, i.e., returns investors could expect to earn if they invest in other enterprises of comparable risk. A benchmark sample of those other enterprises of comparable risk is the guideline sample of 26 electric utilities.

The two obvious measures of the opportunity cost of equity that are available to investors are the ROEs these benchmark utilities are currently earning and the ROEs these utilities are authorized to earn. If regulators authorize rates and rate adjustment mechanisms that allow utilities a reasonable chance to earn their costs of equity, since PGE is more risky than the benchmark sample, either an average of earned ROEs for the sample or an average of authorized ROEs provide information about the minimum ROE that should be authorized for PGE.

PGE Exhibit 1004 provides a list of currently authorized ROEs and ROEs earned in 2006 for utilities in my DCF sample. During 2006, the sample companies earned, on average, 10.9%. The table also reports the most recently authorized ROEs for the 26 sample utilities. In compiling the list of authorized ROEs I report the average ROEs determined by AUS Utility Reports in October 2007 for the benchmark sample companies which provide service in multiple state. For other companies in the sample, I relied on the smaller of the authorized ROEs reported by *Value Line* and AUS Utility Reports (in cases when they were different) to be conservative. Based on these data, the benchmark electric utilities are authorized an average ROE of 10.9%.

Q. Do the earned and authorized ROEs reported in PGE Exhibit 1004 depend upon what types of models were used to determine those ROEs or what assumptions were used to produce equity costs with those models?

A. No, they do not. The evidence in PGE Exhibit 1004 provides a direct estimate of the opportunity cost of equity that ORS 756.040 and the U.S. Supreme Court have found should be considered in determining a fair rate of return on equity. The ultimate test of a fair ROE is where the rates and rate adjustment mechanisms authorized for PGE by the Oregon PUC give PGE a reasonable opportunity to earn the rate of return investors could expect to earn if they invested in another utility of comparable risk. The average of authorized returns and realized ROEs resulting form commission decisions reported in PGE Exhibit 1004 provide a gauge indicating the equity cost estimates in present above are indeed reasonable and PGE's requested ROE of 10.75% is conservative.

Q. Please summarize your testimony.

A. The fair rate of return for PGE should be determined by recognizing that PGE faces a number of risks previously recognized by the Commission, and other risks discussed by Ms. Stathis, Mr. Hager, and me. Ms. Stathis and Mr. Hager explained why PGE continues to require a risk adjustment of 10 basis points to compensate for its exposure to the wholesale market. Once other risk factors are considered, PGE requires a combined risk adjustment of no less than 20 basis points to compensate for its above-average risks.

My equity cost estimates are summarized in PGE Exhibit 1016. Initially, I turned to benchmark DCF estimates based on data for a sample of 26 electric utilities. My first estimate for the benchmark sample of 11.2% is based on the constant growth DCF model and consensus estimates of future EPS growth reported by Reuters, Zacks, Thomson First Call and the S&P Earnings Guide. My second benchmark DCF estimate of 11.3% is based on concepts used by FERC, a range of growth estimates provided by Reuters and *Value Line*, and a conservative forecast of future GDP growth. This approach recognizes investors require higher expected returns for equity than they could obtain by holding less risky Baa bonds and assumes investors expect two-stage growth with the second stage being growth in GDP. Based on this analysis, the indicated required ROE for PGE is 11.5%. My third DCF approach determines an internal rate of return for each of the benchmark sample companies from an examination of expected growth in three future stages. It assumes investors expect growth rates that gradually increase or decrease toward a conservative estimate of future GDP growth. Based on that analysis, the average equity cost for the sample is 10.5% and the indicated required ROE for PGE is 10.7%.

In Section IV, I explain why risk premiums are expected to vary inversely with interest rates and summarize Gordon and Halpern's theory that supports such a relationship. I then present three risk premium studies that used different methods to determine risk premiums: one bases risk premiums on realized book returns on average equity, one determines risk premiums from averages of holding period returns and the other determines risk premiums from a statistical analysis of past litigated electric utilities' decision. Taken together, the risk premium analyses support a benchmark ROE range of 10.8% to 11.2% and an equity cost range of 11.0% to 11.4% for PGE.

I also provide some perspective and checks on my estimates of RROEs. I show that if authorized and earned ROEs for companies in my DCF benchmark sample were considered along with a risk adjustment for PGE of 20 basis points, the indicated fair ROE for PGE would be 11.1%. Taking into account all of the data presented in PGE Exhibit 1016, I estimate PGE's cost of equity for 2009 falls in a range of 10.7% to 11.5%.

Q. Is PGE's requested ROE of 10.75% reasonable?

A. Yes, it is. A 10.75% ROE is very close to the bottom of my range of equity cost estimates and thus is a conservative request.

VI. Qualifications

Q. What is your profession and background?

A. I am an economist and Vice President of Utility Resources, Inc., a consulting firm. I received my Ph.D. in Economics form the University of Florida. Prior to jointly establishing our consulting firm in 1985, I was a consultant at Zinder Companies from 1982-1985. Between 1976 and 1982, I was a senior economist on the staff of the Oregon Public Utility Commissioner. In that position, I conducted studies and prepared testimony on a number of economic and financial issues and estimated fair rates of return for many of the utilities regulated by the Commissioner. Prior to 1976, I taught business and economics courses at the graduate and undergraduate levels at the University of Florida, Central Michigan University and the Joint Graduate Program of Armstrong and Savannah State Colleges.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees in states of Alaska, Arizona, California, Colorado, Georgia, Hawaii, Idaho, Illinois, Iowa, Kentucky, Minnesota, Montana, Nebraska, Nevada, New Mexico, Oklahoma, Oregon, Tennessee, Utah, Washington, West Virginia, and Wyoming, before two Canadian regulatory authorities and before four Federal agencies. In addition to cost of capital studies, I have testified as to values of utility properties, incremental costs of energy and telecommunications services, and appropriate rate designs.

Q. What cost of capital studies shave you prepared before?

A. I have submitted studies or testified on cost of capital and other financial issues before the Interstate Commerce Commission, Bonneville Power Administration, and courts or regulatory agencies in fifteen states.

My studies and testimony have included consideration of the financial health and fair rates of return for General telephone of the Northwest, Illinois Bell Telephone, Nevada Bell Telephone, Pacific Northwest Bell, U S West, Anchorage Municipal Light & Power, Commonwealth Edison, Idaho Power, Iowa-Illinois Gas and Electric, Pacific power & Light, Portland General Electric, Puget Sound Power & Light, Cascade Natural Gas, Mountain Fuel supply, Northern Illinois Gas, Northwest Natural Gas, Anchorage Water Utility, Anchorage Wastewater Utility, Arizona Water Company, Arizona-American Water Company, California-American Water Company, California Water Service, Chaparral City Water Company, Dominguez Water Company, Golden State Water Company, Hawaii-American Water Company, Kentucky-American Water Company, Mountain Water Company, New Mexico-American Water Company, New Mexico Utilities, Inc., Oregon Water Company, paradise Valley Water Company, Park Water Company, San Gabriel Valley Water Company, San Jose Water Company, Southern California Water Company, Suburban Water System, Tennessee-American Water Company, and Valencia Water Company. I have also prepared estimates of the appropriate rates of return for a number of hospitals in Washington, a large insurance company, and U.S. railroads.

Q. Do you have other professional experience related to cost of capital issues?

A. Yes. My article, "Utility Stocks and the Size Effect – Revisited," was published in the *Quarterly Review of Economics and Finance*, Vol. 43, Issue 3, Autumn 2003, pp. 578-582. Also, I published an article "Water Utilities and Risk," *Water the Magazine of the National Association of Water Companies*, Vol. 40, No. 1 Winter 1999 and was an invited speaker on the topic of risk of water utilities at the 57th Annual Western Conference of Public Utility Commissioners in June 1998. I presented a paper "Application of the Capital Asset pricing

Model in the Regulatory Setting" at the 47th Annual Southern Economic Association Conference and published an article "On the Use of the CAPM in Public Utility Rate Cases: Comment," *Financial Management* Autumn 1978, pp. 52-56. I have been a journal referee for the *International Review of Economics and Finance* and *Financial Management*. While on the staff of the Oregon PUC, I also established a sample of over 500,000 observations of common stock returns and measures of risk and conducted a number of studies related to the use of various methods to estimate costs of equity for utilities. I was invited to Stanford University to discuss that research.

Q. Does this complete your prefiled testimony?

A. Yes.

List of Exhibits

Portland General Electric

Exhibit 1001

Comparison of Risk Factors for PGE and the DCF Electric Utilities Sample

			Percentage of Electric Revenues[c]	S&P Business Profile[a]	Value Line Beta[b]	S&P Bond Rating[c]	Size[d] ($ millions)	Forecasted Future Equity Ratio[b,e]	Percentage of Purchased Power[b]
1	ALLETE	ALE	84%	6	0.95	A-	$1,298	59.0%	32%
2	Alliant Energy	LNT	71%	5	0.90	A-	$4,173	52.0%	42%
3	Ameren	AEE	82%	7	0.80	BBB-	$10,544	53.0%	2%
4	Amer Elect Pwr	AEP	92%	5	1.15	BBB	$18,732	44.0%	na
5	Central Vermont	CV	100%	na	0.85	BBB	$365	52.5%	52%
6	CLECO	CNL	96%	6	1.35	BBB+	$1,371	48.5%	56%
7	DPL Inc	DPL	100%	5	0.90	BBB+	$2,939	47.5%	na
8	DTE Energy	DTE	52%	6	0.80	BBB+	$7,642	45.5%	17%
9	Duke	DUK	59%	5	nmf	A	$23,159	58.0%	5%
10	Edison International	EIX	80%	5	1.05	A	$17,474	49.0%	56%
11	Empire District	EDE	86%	6	0.85	BBB+	$736	48.5%	37%
12	Entergy	ETR	82%	6	0.85	BBB+	$19,400	50.5%	41%
13	FPL Group	FPL	77%	4	0.80	A	$24,653	51.0%	17%
14	Hawaiian	HE	83%	5	0.70	BBB	$1,775	48.0%	38%
15	IDACORP	IDA	99%	5	1.00	A	$1,476	50.0%	24%
16	PG&E	PCG	71%	5	0.95	BBB+	$16,832	53.0%	na
17	Pinnacle West	PNW	80%	6	1.00	BBB-	$3,963	51.0%	35%
18	PNM Resources	PNM	79%	6	0.95	BBB	$1,821	51.5%	0%
19	Portland General	POR	99%	5	nmf	BBB+	$1,681	48.5%	49%
20	PPL	PPL	66%	7	0.95	A-	$18,279	50.0%	na
21	Progress Energy	PGN	89%	5	0.95	A-	$12,178	50.0%	6%
22	Southern Company	SO	98%	4	0.75	A	$27,731	44.0%	5%
23	TECO	TE	61%	5	1.10	BBB-	$3,351	40.0%	13%
24	Westar	WR	73%	5	0.90	BBB-	$2,306	50.0%	0%
25	Wisconsin Energy	WEC	63%	4	0.80	A-	$5,049	47.5%	14%
26	Xcel Energy	XEL	78%	5	1.05	A-	$8,822	47.0%	na
	Average		81%	5	0.93	BBB+	$9,144	50%	26%
	Portland General		99%	5	nmf	BBB+	$1,681	50%	49%

Notes and Sources

a/ From S&P, Ratings Direct: U.S. Integrated Utility and Merchant Power Companies, Strongest to Weakest, September 28, 2007. A business profile of 1 is least risky.

b/ Value Line Ratings & Reports dated August 31, 2007, September 28, 2007, and November 9, 2007.

c/ AUS Utilty Reports, October 2007.

d/ Size based on average price for July to September 2007 and shares reported by AUS Utility Reports, October 2007or from Company.

e/ Equity ratio forecasted by PGE.

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Portland General Electric

Exhibit 1002

Comparison of Value Line Estimates of Betas and Common Equity Ratios for the DCF Electric Utilities Sample

		Value Line Beta Estimates			Common Equity Ratios	
		2007-[a/]	2003-[b/]	Higher or Lower Risk in 2007?	2007-[a/]	2003-[a/]
1	ALLETE	0.95	0.75	higher	_c/	na
2	Alliant Energy	0.90	0.75	higher	56.5%	50.0%
3	Ameren	0.80	0.70	higher	54.0%	50.6%
4	Amer Elect Pwr	1.15	1.05	higher	42.5%	38.7%
5	Central Vermont	0.85	0.45	higher	53.5%	57.8%
6	CLECO	1.35	1.00	higher	54.0%	33.8%
7	DPL Inc	0.90	0.85	higher	37.0%	31.3%
8	DTE Energy	0.80	0.65	higher	45.0%	40.8%
9	Duke	nmf	nmf	na	_c/	na
10	Edison International	1.05	0.95	higher	45.5%	31.1%
11	Empire District	0.85	0.65	higher	47.5%	48.0%
12	Entergy	0.85	0.70	higher	48.0%	53.2%
13	FPL Group	0.80	0.65	higher	51.0%	44.4%
14	Hawaiian	0.70	0.60	higher	46.5%	49.8%
15	IDACORP	1.00	0.80	higher	52.5%	46.4%
16	PG&E	0.95	na	na	52.5%	53.9%
17	Pinnacle West	1.00	0.80	higher	51.5%	49.4%
18	PNM Resources	0.95	0.80	higher	49.5%	51.9%
19	Portland General	nmf	nmf	na	_c/	na
20	PPL	0.95	0.90	higher	42.5%	28.5%
21	Progress Energy	0.95	0.80	higher	48.5%	43.4%
22	Southern Company	0.75	0.60	higher	46.0%	43.6%
23	TECO	1.10	0.80	higher	35.0%	27.6%
24	Westar	0.90	0.70	higher	49.5%	33.2%
25	Wisconsin Energy	0.80	0.65	higher	45.0%	39.6%
26	Xcel Energy	1.05	0.75	higher	47.5%	43.8%
	Average	0.93	0.75	higher	47.9%	43.1%

Notes and Sources

a/ Value Line Ratings & Reports dated August 31, 2007, September 28, 2007, and November 9, 2007.
b/ Value Line Summary & Index, December 26, 2003.
c/ Not included since earlier data not available.

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Portland General Electric

Exhibit 1003

Comparison of EPS Growth Forecasts for 2004, 2005, 2006 and 2007

		S&P Earnings Guide Oct 2007	S&P Earnings Guide Dec 2006	S&P Earnings Guide Dec 2005	S&P Earnings Guide Dec 2004
1	ALLETE	5.0	9.0	7.0	7.0
2	Alliant Energy	6.0	5.0	4.0	7.0
3	Ameren	7.0	4.0	5.0	4.0
4	Amer Elect Pwr	6.0	4.0	4.0	4.0
5	Central Vermont	_b/	_b/	na	na
6	CLECO	12.0	11.0	5.0	4.0
7	DPL Inc	6.0	7.0	5.0	5.0
8	DTE Energy	6.0	5.0	6.0	6.0
9	Duke	5.0	6.0	6.0	4.0
10	Edison International	7.0	7.0	7.0	5.0
11	Empire District	19.0	6.0	2.0	3.0
12	Entergy	10.0	8.0	7.0	5.0
13	FPL Group	9.0	8.0	6.0	5.0
14	Hawaiian	2.0	3.0	4.0	3.0
15	IDACORP	6.0	5.0	4.0	na
16	PG&E	9.0	8.0	5.0	6.0
17	Pinnacle West	6.0	5.0	6.0	5.0
18	PNM Resources	10.0	12.0	11.0	5.0
19	Portland General	_b/	na	na	na
20	PPL	12.0	11.0	7.0	5.0
21	Progress Energy	5.0	4.0	4.0	5.0
22	Southern Company	5.0	3.0	7.0	5.0
23	TECO	3.0	3.0	7.0	4.0
24	Westar	5.0	6.0	3.0	4.0
25	Wisconsin Energy	9.0	8	8.0	5.0
26	Xcel Energy	6.0	6.4	5.7	4.8
	Average	7.3	6.4	5.7	4.8

Notes and Sources:

a/ Sources are indicated copies of the S&P Earnings Guide.

b/ Data not included since data for eariler years are not available.

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Portland General Electric

Exhibit 1004

Checks on RROE Estimates:
Earned and Authorized ROEs for DCF Sample

		Earned ROE[a]	Authorized ROE[c]
1	ALLETE	12.1%	11.60%
2	Alliant Energy	9.5%	10.70%
3	Ameren	8.5%	10.37%
4	Amer Elect Pwr	12.1%	11.05%
5	Central Vermont	8.9%	10.75%
6	CLECO	9.3%	11.25%
7	DPL Inc	14.4%	11.00%
8	DTE Energy	7.5%	11.00%
9	Duke[b]	7.7%	11.18%
10	Edison International	15.1%	11.60%
11	Empire District	9.2%	10.90%
12	Entergy	14.2%	10.81%
13	FPL Group	14.1%	11.75%
14	Hawaiian	9.3%	10.82%
15	IDACORP	9.3%	10.25%
16	PG&E	13.2%	11.35%
17	Pinnacle West	9.2%	10.25%
18	PNM Resources	8.1%	10.13%
19	Portland General	5.9%	10.10%
20	PPL	17.8%	9.57%
21	Progress Energy	6.3%	12.42%
22	Southern Company	14.3%	12.20%
23	TECO	14.7%	11.25%
24	Westar	10.9%	10.00%
25	Wisconsin Energy	11.1%	11.20%
26	Xcel Energy	10.1%	10.83%
	Average	10.9%	10.9%

Notes and Sources:

a/ As reported by Value Line in footnotes to Ratings & Reports for each company for 2006.

b/ As reported by AUS Utility Reports. Data not available in Value Line.

c/ The most recent authorized ROEs reported by AUS Utility Reports or Value Line (as of November 9, 2007).

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Portland General Electric

Exhibit 1005

Current Annualized Average Dividend Yields for Water Utilities Sample

			Yield-[a/] Based on 3-month-[b/] Range of Prices	Value Line Dividend Forecast-[a/] Adjusted for Time Value of Money	3-month-[b/] High Stock Price	3-month-[b/] Low Stock Price
1	ALLETE	ALE	4.12%	$1.79	$50.05	$38.42
2	Alliant Energy	LNT	3.59%	$1.35	$40.80	$34.95
3	Ameren	AEE	5.26%	$2.64	$53.89	$47.10
4	Amer Elect Pwr	AEP	3.78%	$1.72	$48.83	$42.46
5	Central Vermont	CV	2.64%	$0.96	$41.05	$32.38
6	CLECO	CNL	3.89%	$0.94	$26.42	$22.14
7	DPL Inc	DPL	3.99%	$1.09	$29.75	$25.41
8	DTE Energy	DTE	4.68%	$2.26	$51.74	$45.26
9	Duke	DUK	5.06%	$0.93	$19.90	$16.91
10	Edison International	EIX	2.28%	$1.25	$59.57	$50.64
11	Empire District	EDE	5.90%	$1.33	$24.29	$21.09
12	Entergy	ETR	3.09%	$3.12	$111.95	$91.94
13	FPL Group	FPL	2.96%	$1.75	$64.20	$54.61
14	Hawaiian	HE	5.88%	$1.29	$23.91	$20.25
15	IDACORP	IDA	3.78%	$1.25	$36.57	$30.07
16	PG&E	PCG	3.36%	$1.53	$48.78	$42.58
17	Pinnacle West	PNW	5.72%	$2.24	$41.76	$36.79
18	PNM Resources	PNM	3.94%	$0.96	$28.71	$21.05
19	Portland General	POR	3.67%	$1.00	$29.13	$25.50
20	PPL	PPL	2.73%	$1.33	$52.79	$45.40
21	Progress Energy	PGN	5.53%	$2.55	$49.48	$43.12
22	Southern Company	SO	4.84%	$1.71	$37.70	$33.16
23	TECO	TE	5.09%	$0.82	$17.71	$14.84
24	Westar	WR	4.67%	$1.14	$26.44	$22.84
25	Wisconsin Energy	WEC	2.50%	$1.08	$45.81	$41.06
26	Xcel Energy	XEL	4.63%	$0.97	$22.41	$19.59
	Average		4.14%	$1.50		

Sources and Notes:

a/ Dividend yields (D_1/P_0) are based on Value Line's August 31, 2007 forecasts of dividends (D_1) for the next year corrected for the time value of money with the quarterly DCF model.

b/ The price (P_0) is the average of the high and low prices for the period July 2007 to September 2007.

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Portland General Electric

Exhibit 1006

Estimates of Growth Based on Analysts' Forecasts Reported by Reuters, S&P Earnings Guide, First Call and Zacks[a]

		Reuters Data				Other Sources of Analysts' Forecasts: S&P Earnings Guide[a]			First	
		# of Ests	Mean	High	Low	# of Ests	Mean	Zacks[a]	Call[a]	Average[c]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	ALLETE	2	8.8	12.5	5.0	2	5.0	5.0	5.00	5.9
2	Alliant Energy	3	5.7	7.0	5.0	3	6.0	6.0	5.67	5.8
3	Ameren	5	7.9	13.0	3.5	10	7.0	6.8	7.33	7.3
4	Amer Elect Pwr	8	5.1	6.5	2.0	13	6.0	4.7	5.91	5.4
5	Central Vermont	1	10.0	10.0	10.0	1	10.0	na	10.00	10.0
6	CLECO	na	na	na	na	6	12.0	5.0	12.00	9.7
7	DPL Inc	3	8.3	10.0	5.0	5	6.0	9.0	6.33	7.4
8	DTE Energy	5	6.0	8.0	4.0	10	6.0	5.7	5.75	5.9
9	Duke	6	6.3	11.0	5.0	13	5.0	6.4	5.33	5.8
10	Edison International	7	8.1	11.0	6.0	13	7.0	9.7	6.85	7.9
11	Empire District	na	na	na	na	4	19.0	na	34.00	19.0 [d]
12	Entergy	4	9.5	14.0	7.0	15	10.0	12.8	10.40	10.7
13	FPL Group	7	9.4	12.0	6.0	17	9.0	10.3	9.29	9.5
14	Hawaiian	5	3.2	6.0	2.0	4	2.0	4.5	2.27	3.0
15	IDACORP[b]	2	5.0	5.0	5.0	6	6.0	6.0	5.00	5.5
16	PG&E	6	8.2	9.4	7.5	14	9.0	8.6	8.88	8.7
17	Pinnacle West	4	7.8	12.0	5.0	10	6.0	6.7	5.73	6.6
18	PNM Resources	6	9.8	18.8	6.0	10	10.0	8.8	10.47	9.8
19	Portland General	2	5.9	7.8	4.0	no	na	4.0	4.00	4.6
20	PPL	6	11.7	20.0	5.0	11	12.0	13.0	12.00	12.2
21	Progress Energy	6	4.4	5.0	2.5	15	5.0	4.5	5.07	4.7
22	Southern Company	7	4.7	5.2	3.0	17	5.0	4.3	5.03	4.8
23	TECO	4	6.3	14.0	3.0	11	3.0	6.7	3.00	4.7
24	Westar	5	4.4	7.1	3.0	4	5.0	4.5	5.37	4.8
25	Wisconsin Energy	6	9.4	11.2	6.0	13	9.0	9.3	9.04	9.2
26	Xcel Energy	6	5.3	9.0	3.0	11	6.0	4.8	5.60	5.4
	Average		7.1	10.2	4.7		7.4	7.0	7.9	7.5

Notes and Sources:

a/ Sources are analysts' forecasts reported on the Internet on October 12, 2007 and in the October 2007 S&P Earnings Guide.

b/ With the exception IDACORP, all other analysts' forecasts fall within the range reported by Reuters.

c/ Average of all available forecasts with the exception of Empire District.

d/ Estimate for Empire District does not include forecast reported by First Call.

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Exhibit 1007

Application of the Constant Growth DCF Model Based on Analysts' Forecasts of Growth Reported by Reuters, S&P Earnings Guide, Zacks and First Call

			D_1/P_0 [a]	G [b]	Equity Cost Estimates	
1	ALLETE	ALE	4.12%	5.94%	10.05%	
2	Alliant Energy	LNT	3.59%	5.84%	9.43%	
3	Ameren	AEE	5.26%	7.26%	12.51%	
4	Amer Elect Pwr	AEP	3.78%	5.43%	9.21%	
5	Central Vermont	CV	2.64%	10.00%	12.64%	
6	CLECO	CNL	3.89%	9.67%	13.55%	
7	DPL Inc	DPL	3.99%	7.41%	11.39%	
8	DTE Energy	DTE	4.68%	5.86%	10.54%	
9	Duke	DUK	5.06%	5.77%	10.83%	
10	Edison International	EIX	2.28%	7.92%	10.20%	
11	Empire District	EDE	5.90%	19.00%	24.90%	[c]
12	Entergy	ETR	3.09%	10.68%	13.77%	
13	FPL Group	FPL	2.96%	9.51%	12.47%	
14	Hawaiian	HE	5.88%	2.99%	8.88%	
15	IDACORP	IDA	3.78%	5.50%	9.28%	
16	PG&E	PCG	3.36%	8.68%	12.04%	
17	Pinnacle West	PNW	5.72%	6.56%	12.28%	
18	PNM Resources	PNM	3.94%	9.77%	13.71%	
19	Portland General	POR	3.67%	4.63%	8.31%	[c]
20	PPL	PPL	2.73%	12.17%	14.90%	
21	Progress Energy	PGN	5.53%	4.75%	10.28%	
22	Southern Company	SO	4.84%	4.77%	9.60%	
23	TECO	TE	5.09%	4.74%	9.83%	
24	Westar	WR	4.67%	4.82%	9.49%	
25	Wisconsin Energy	WEC	2.50%	9.18%	11.68%	
26	Xcel Energy	XEL	4.63%	5.43%	10.06%	
	Unadjusted average				11.61%	
	Constrained average (drop highest and lowest from average) [c]				11.19%	

Notes and Sources:

a/ Dividend yields (D_1/P_0) developed in Table 4.

b/ Growth is the average growth rate reported in Table 5.

c/ Empire District and Portland General not included in constrained average.

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Portland General Electric

Exhibit 1008

Range of Growth Rates Reported by Value Line and Reuters[a]

		Value Line EPS Growth Forecast	Reuters or Other[a] Analysts' Forecasts		Range of Forecasts		
			Maximum	Minimum	Highest	Lowest	Mid-point
1	ALLETE	10.5	12.5	5.0	12.5	5.0	8.8
2	Alliant Energy	5.0	7.0	5.0	7.0	5.0	6.0
3	Ameren	2.5	13.0	3.5	13.0	2.5	7.8
4	Amer Elect Pwr	6.5	6.5	2.0	6.5	2.0	4.3
5	Central Vermont	9.0	10.0	10.0	10.0	9.0	9.5
6	CLECO[a]	4.0	12.0	5.0	12.0	4.0	8.0
7	DPL Inc	8.5	10.0	5.0	10.0	5.0	7.5
8	DTE Energy	5.5	8.0	4.0	8.0	4.0	6.0
9	Duke	6.9	11.0	5.0	11.0	5.0	8.0
10	Edison International	6.5	11.0	6.0	11.0	6.0	8.5
11	Empire District[a]	11.0	19.0	19.0	19.0	11.0	15.0
12	Entergy	9.5	14.0	7.0	14.0	7.0	10.5
13	FPL Group	8.5	12.0	6.0	12.0	6.0	9.0
14	Hawaiian	1.5	6.0	2.0	6.0	1.5	3.8
15	IDACORP	2.0	5.0	5.0	5.0	2.0	3.5
16	PG&E	4.5	9.4	7.5	9.4	4.5	6.9
17	Pinnacle West	3.5	12.0	5.0	12.0	3.5	7.8
18	PNM Resources	3.5	18.8	6.0	18.8	3.5	11.2
19	Portland General	14.5	7.8	4.0	14.5	4.0	9.3
20	PPL	13.0	20.0	5.0	20.0	5.0	12.5
21	Progress Energy	3.5	5.0	2.5	5.0	2.5	3.8
22	Southern Company	3.0	5.2	3.0	5.2	3.0	4.1
23	TECO	4.5	14.0	3.0	14.0	3.0	8.5
24	Westar	4.5	7.1	3.0	7.1	3.0	5.0
25	Wisconsin Energy	8.0	11.2	6.0	11.2	6.0	8.6
26	Xcel Energy	5.5	9.0	3.0	9.0	3.0	6.0
	Column average						7.7

Notes and Sources:

a/ Reuters forecasts not available. Forecasts for Cleco based on all other analysts' forecasts.
Forecasts for Empire District based on data reported by S&P Earnings Guide.

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Portland General Electric

Exhibit 1009

Application of the FERC Multi-period DCF Method Based on Highest and Lowest Forecasts of Growth Reported by Reuters and Value Line

		D_1/P_0	High Growth	High Equity Cost Estimate	Low Growth	Low Equity Cost Estimate	
1	ALLETE	4.12%	10.29%	14.41%	5.26%	9.38%	
2	Alliant Energy	3.59%	6.60%	10.20%	5.26%	8.86%	
3	Ameren	5.26%	10.62%	15.88%	3.59%	8.85%	
4	Amer Elect Pwr	3.78%	6.27%	10.05%	3.25%	7.03%	_b/
5	Central Vermont	2.64%	8.61%	11.26%	7.94%	10.59%	
6	CLECO	3.89%	9.95%	13.84%	4.59%	8.48%	
7	DPL Inc	3.99%	8.61%	12.60%	5.26%	9.25%	
8	DTE Energy	4.68%	7.27%	11.95%	4.59%	9.27%	
9	Duke	5.06%	9.28%	14.35%	5.26%	10.33%	
10	Edison International	2.28%	9.28%	11.56%	5.93%	8.21%	
11	Empire District	5.90%	14.64%	20.54%	9.28%	15.18%	
12	Entergy	3.09%	11.29%	14.39%	6.60%	9.70%	
13	FPL Group	2.96%	9.95%	12.92%	5.93%	8.90%	
14	Hawaiian	5.88%	5.93%	11.82%	2.92%	8.80%	
15	IDACORP	3.78%	5.26%	9.05%	3.25%	7.04%	_b/
16	PG&E	3.36%	8.20%	11.56%	4.93%	8.29%	
17	Pinnacle West	5.72%	9.95%	15.67%	4.26%	9.98%	
18	PNM Resources	3.94%	14.51%	18.45%	4.26%	8.20%	
19	Portland General	3.67%	11.63%	15.30%	4.59%	8.27%	
20	PPL	2.73%	15.31%	18.04%	5.26%	7.99%	
21	Progress Energy	5.53%	5.26%	10.80%	3.59%	9.12%	
22	Southern Company	4.84%	5.40%	10.23%	3.92%	8.76%	
23	TECO	5.09%	11.29%	16.38%	3.92%	9.01%	
24	Westar	4.67%	6.66%	11.33%	3.92%	8.59%	
25	Wisconsin Energy	2.50%	9.43%	11.93%	5.93%	8.43%	
26	Xcel Energy	4.63%	7.94%	12.57%	3.92%	8.55%	
	Average			13.3%		9.2%	
	Mid-point of High and Low Equity Costs				11.3%		

Sources and Notes:

a/ Growth rates are computed as two-thirds times the respective growth rates reported in Table 8 and one-third times a GDP forecast of 5.8%.

b/ Not included. Equity cost below expected cost of Baa bonds. See Table 11.

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Portland General Electric

Exhibit 1010

Multi-Stage DCF Growth Analysis

		Internal Rate of Return	P_{2007}	First Year Dividend D_1 [a]	Stage 1 [b]		Stage 2 and 3 [c,d]			
				D_{2008}	D_{2009}	D_{2013}	D_{2014}	D_{2022}	$(P+D)_{2023}$	P_{2023} [d]
1	ALLETE	11.05%	-$41.87	$1.79	$1.95	$2.72	$2.95	$5.12	$114.67	$109.26
2	Alliant Energy	9.31%	-$39.00	$1.35	$1.43	$1.81	$1.92	$3.03	$99.51	$96.30
3	Ameren	11.77%	-$50.45	$2.64	$2.85	$3.84	$4.13	$6.92	$137.11	$129.78
4	Amer Elect Pwr	9.06%	-$46.83	$1.72	$1.79	$2.11	$2.21	$3.29	$116.29	$112.81
5	Central Vermont	9.27%	-$36.48	$0.96	$1.05	$1.51	$1.64	$2.92	$97.65	$94.55
6	CLECO	10.59%	-$22.85	$0.94	$1.01	$1.38	$1.48	$2.51	$61.27	$58.62
7	DPL Inc	10.50%	-$26.24	$1.09	$1.17	$1.57	$1.68	$2.80	$69.66	$66.70
8	DTE Energy	10.56%	-$48.06	$2.26	$2.39	$3.02	$3.20	$5.06	$124.26	$118.91
9	Duke	11.65%	-$18.38	$0.93	$1.00	$1.36	$1.47	$2.48	$50.12	$47.50
10	Edison International	8.71%	-$53.60	$1.25	$1.35	$1.88	$2.03	$3.49	$141.09	$137.40
11	Empire District	15.41%	-$23.74	$1.33	$1.53	$2.68	$3.06	$6.51	$81.07	$74.18
12	Entergy	10.18%	-$100.00	$3.12	$3.45	$5.14	$5.66	$10.40	$276.60	$265.59
13	FPL Group	9.49%	-$60.13	$1.75	$1.91	$2.69	$2.92	$5.11	$160.48	$155.07
14	Hawaiian	11.07%	-$21.26	$1.29	$1.34	$1.55	$1.61	$2.36	$52.61	$50.11
15	IDACORP	8.96%	-$33.32	$1.25	$1.29	$1.48	$1.54	$2.23	$82.13	$79.77
16	PG&E	9.54%	-$44.53	$1.53	$1.64	$2.14	$2.28	$3.73	$115.76	$111.81
17	Pinnacle West	12.22%	-$39.63	$2.24	$2.41	$3.25	$3.49	$5.86	$108.39	$102.19
18	PNM Resources	11.63%	-$23.65	$0.96	$1.06	$1.62	$1.80	$3.37	$68.45	$64.88
19	Portland General	10.55%	-$26.89	$1.00	$1.09	$1.55	$1.69	$2.99	$73.56	$70.41
20	PPL	10.31%	-$47.85	$1.33	$1.50	$2.40	$2.68	$5.27	$136.44	$130.86
21	Progress Energy	10.51%	-$46.84	$2.55	$2.64	$3.06	$3.19	$4.66	$115.75	$110.82
22	Southern Company	9.96%	-$36.25	$1.71	$1.78	$2.09	$2.17	$3.22	$90.07	$86.66
23	TECO	12.00%	-$15.88	$0.82	$0.89	$1.24	$1.34	$2.30	$44.03	$41.59
24	Westar	10.12%	-$25.07	$1.14	$1.20	$1.46	$1.54	$2.35	$63.44	$60.95
25	Wisconsin Energy	8.93%	-$43.15	$1.08	$1.18	$1.64	$1.77	$3.06	$113.76	$110.52
26	Xcel Energy	10.55%	-$20.66	$0.97	$1.03	$1.29	$1.37	$2.17	$53.41	$51.12
	Average	10.5%								

Notes and Sources:

a/ Value Line forecast of DPS growth adjusted for the time value of money. See Table 5.
b/ Mid-point of range of Reuters and Value Line EPS forecasts of growth from Table 8.
c/ Growth based on gradual transition from analysts' forecasts of growth to expected long-term average GDP growth of 5.8%.
d/ Price received at end of stage 2.

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0.1 0.9 1

5.80% future GDP growth (top of range of GDP forecasts for 2009 from Blue Chip)
assumes long term will be closer to the past.

Portland General Electric

Exhibit 1011

Forecasts of Interest Rates for 2009

Type of Security	2009
Baa Corporate Bond Rates	
Blue Chip Consensus Forecast[a/]	7.00%
Global Insight[b/]	7.12%
Average	7.06%
10-Year Treasury Securities	
Blue Chip Consensus Forecast[a/]	4.90%
Global Insight[b/]	5.05%
Average	4.98%
Average	
Long-term Treasury Bonds	
Blue Chip Consensus Forecast[a/]	5.20%
Global Insight[b/]	5.33%
Average	5.27%

Sources and Notes:
a/ October 2007 Blue Chip consensus forecasts for first quarter of 2009.
b/ Global Insight October 2007 Financial Markets Analysis for 2009.

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Portland General Electric

Exhibit 1012

Risk Premium Analysis Method Used by Department of Ratepayer Advocates of the California PUC-[a/] but with Data for OPUC Staff Sample in UE 180

	Return on Equity-[b/]	Annual Averages		Risk Premiums		
		Long-term Treasury-[c/]	10-Year Treasury-[c/]	Long-term Treasury		10-Year Treasury
1997	11.14%	6.61%	6.35%	4.53%		4.79%
1998	11.61%	5.58%	5.26%	6.03%		6.35%
1999	11.67%	5.87%	5.65%	5.80%		6.02%
2000	11.30%	5.94%	6.03%	5.36%		5.27%
2001	11.80%	5.49%	5.02%	6.31%		6.78%
2002	10.66%	5.43%	4.61%	5.23%		6.05%
2003	10.75%	4.96%	4.01%	5.79%		6.74%
2004	10.60%	5.04%	4.27%	5.56%		6.33%
2005	10.60%	4.64%	4.29%	5.96%		6.31%
2006	10.74%	4.91%	4.80%	5.83%		5.94%
	10-Year Average Premium			5.64%		6.06%
	5-year Average Premium			5.67%		6.27%
	Expected Treasury Rates for 2009-[d/]			5.27%		4.98%
	Projected Returns on Equity					
	10-Year Average			10.9%		11.0%
	5-Year Average			10.9%		11.2%
	Indicated Cost of Equity Range for PGE			11.1%	to	11.4%

Notes and Sources:

a/ Method developed in Division of Ratepayer Advocates, CPUC, *Report on the Cost of Capital for San Jose Water,* June 2006, A.06-02-014, Table 2-7.

b/ Average of earned ROEs for the 14 Utilities relied upon by the OPUC in UE-180. Data from PUC Staff 2006 workpapers with updated data for 2006 from various Value Line documents current as of December 29, 2006.

c/ Federal Reserve data. Long term rate is 30-year rate if available, otherwise the 20-year rate.

d/ Source in Table 11.

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Portland General Electric

Exhibit 1013: Risk Premium Analysis Based on Holding Period Returns for Moody's Electric Utilities Sample as Updated, 1950 to 2006

	Baa Corporate Bond Rate[a]	Year-end Price Index[b]	Annual Average Dividend[b]	Index Gain/Loss	Dividend Yield	Total Return	Risk Premium
1950	3.20%	$30.81					
1951	3.61%	$33.85	$1.88	9.87%	6.10%	15.97%	12.77%
1952	3.51%	$37.85	$1.91	11.82%	5.64%	17.46%	13.85%
1953	3.74%	$39.61	$2.01	4.65%	5.31%	9.96%	6.45%
1954	3.45%	$47.56	$2.13	20.07%	5.38%	25.45%	21.71%
1955	3.62%	$49.35	$2.21	3.76%	4.65%	8.41%	4.96%
1956	4.37%	$48.96	$2.32	-0.79%	4.70%	3.91%	0.29%
1957	5.03%	$50.30	$2.43	2.74%	4.96%	7.70%	3.33%
1958	4.85%	$66.37	$2.50	31.95%	4.97%	36.92%	31.89%
1959	5.28%	$65.77	$2.61	-0.90%	3.93%	3.03%	-1.82%
1960	5.10%	$76.82	$2.68	16.80%	4.07%	20.88%	15.60%
1961	5.10%	$99.32	$2.81	29.29%	3.66%	32.95%	27.85%
1962	4.92%	$96.49	$2.97	-2.85%	2.99%	0.14%	-4.96%
1963	4.85%	$102.31	$3.21	6.03%	3.33%	9.36%	4.44%
1964	4.81%	$115.54	$3.43	12.93%	3.35%	16.28%	11.43%
1965	5.02%	$114.86	$3.86	-0.59%	3.34%	2.75%	-2.06%
1966	6.18%	$105.99	$4.11	-7.72%	3.58%	-4.14%	-9.16%
1967	6.93%	$98.19	$4.34	-7.36%	4.09%	-3.26%	-9.44%
1968	7.23%	$104.04	$4.50	5.96%	4.58%	10.54%	3.61%
1969	8.65%	$84.62	$4.61	-18.67%	4.43%	-14.23%	-21.46%
1970	9.12%	$88.59	$4.70	4.69%	5.55%	10.25%	1.60%
1971	8.38%	$85.56	$4.77	-3.42%	5.38%	1.96%	-7.16%
1972	7.93%	$83.61	$4.87	-2.28%	5.69%	3.41%	-4.97%
1973	8.48%	$60.87	$5.01	-27.20%	5.99%	-21.21%	-29.14%
1974	10.63%	$41.17	$4.83	-32.36%	7.93%	-24.43%	-32.91%
1975	10.56%	$55.66	$4.97	35.20%	12.07%	47.27%	36.64%
1976	9.12%	$66.29	$5.18	19.10%	9.31%	28.40%	17.84%
1977	8.99%	$68.19	$5.54	2.87%	8.36%	11.22%	2.10%
1978	9.94%	$59.75	$5.81	-12.38%	8.52%	-3.86%	-12.85%
1979	12.06%	$56.41	$6.22	-5.59%	10.41%	4.82%	-5.12%
1980	14.64%	$54.42	$6.58	-3.53%	11.66%	8.14%	-3.92%
1981	16.55%	$57.20	$6.99	5.11%	12.84%	17.95%	3.31%
1982	14.14%	$70.26	$7.43	22.83%	12.99%	35.82%	19.27%
1983	13.75%	$72.03	$7.87	2.52%	11.20%	13.72%	-0.42%
1984	13.40%	$80.16	$8.26	11.29%	11.47%	22.75%	9.00%
1985	11.58%	$94.98	$8.61	18.49%	10.74%	29.23%	15.83%
1986	9.97%	$113.66	$8.89	19.67%	9.36%	29.03%	17.45%
1987	11.29%	$94.24	$9.12	-17.09%	8.02%	-9.06%	-19.03%
1988	10.65%	$100.94	$8.87	7.11%	9.41%	16.52%	5.23%
1989	9.82%	$122.52	$8.82	21.38%	8.74%	30.12%	19.47%
1990	10.43%	$117.77	$8.79	-3.88%	7.17%	3.30%	-6.52%
1991	9.26%	$144.02	$8.95	22.29%	7.60%	29.89%	19.46%
1992	8.81%	$141.06	$9.05	-2.06%	6.28%	4.23%	-5.03%
1993	7.69%	$146.70	$8.99	4.00%	6.37%	10.37%	1.56%
1994	9.10%	$115.50	$8.96	-21.27%	6.11%	-15.16%	-22.85%
1995	7.49%	$142.90	$9.02	23.72%	7.81%	31.53%	22.43%
1996	7.89%	$136.00	$9.06	-4.83%	6.34%	1.51%	-5.98%
1997	7.32%	$155.73	$9.06	14.51%	6.66%	21.17%	13.28%
1998	7.23%	$181.84	$7.83	16.77%	5.03%	21.79%	14.47%
1999	8.19%	$137.30	$8.10	-24.49%	4.45%	-20.04%	-27.27%
2000	8.02%	$227.09	$8.27	65.40%	6.02%	71.42%	63.23%
2001	8.05%	$206.02	$7.44	-9.28%	3.28%	-6.01%	-14.03%
2002	7.45%	$178.17	$7.48	-13.52%	3.63%	-9.89%	-17.94%
2003	6.60%	$187.34	$7.16	5.15%	4.02%	9.17%	1.72%
2004	6.15%	$223.18	$7.27	19.13%	3.88%	23.01%	16.41%
2005	6.32%	$240.06	$7.63	7.57%	3.42%	10.98%	4.83%
2006	6.22%	$273.48	$7.84	13.92%	3.27%	17.19%	10.87%

	Updated Study	Original Study
Average Baa rate	8.0%	8.1%
Unadjusted risk premium	3.8%	4.2%
Expected Baa bond rate	7.1%	7.1%
Adjusted risk premium[c]	4.1%	4.6%
Estimated cost of equity	11.2%	11.7%

Notes and Sources:

a/ Federal Reserve data. Monthly rates for December of the indicated year.

b/ Mergent, Moody's 2001 Public Utility Manual with updates for 2001-2006.

c/ Adjustment is based on California PUC decision which found equity costs change 50% to 67% as much as interest rates and study by Roger Morin. Assume CPUC conservative adjustment of 33%.

11/09/07

Portland General Electric

Exhibit 1014

Risk Premiums Determined by Relationship Between Authorized ROEs and 30-year Treasury Rates[a] During the Period 1985-2006

Regression Output:

Constant (A_0)		0.0770
Std Err of Y Est		0.0081
R Squared		50.9%
No. of Observations		456
Degrees of Freedom		454
Slope (A_1)	-0.4029	
Std Err of Coef.	0.0186	
t-statistic	-27.9460	

Equity Cost Estimate		Predicted Risk Premium		10-Year Treasury Rate[b]
10.8%	=	5.6%	+	5.2%
10.9%	=	5.6%	+	5.3%

Formula: Risk Premium = A_0 + (A_1 x 30-Year Treasury Rate)[c]

Sources and Notes:

_a/ Source of ROE Data: Oregon PUC Response to NW Natural Data request in UG 132 updated with data in Phillip Cross, Rate of Return: Still an Issue at PUCs, Public Utilities Fortnightly, December 1998 and 2000 plus decisions reported by Regulatory Research Associates for 1999-2006.

_b/ Top of range: Global Insight forecast for 2009, October 2007. Bottom of range: Blue Chip Consensus forecast for first quarter 2009, October 2007.

_c/ 6-month lag between order date and Treasury interest rates adopted.

11/9/07

Portland General Electric

Exhibit 1015

Risk Premiums Deternined by Relationship Between Authorized ROEs and 30-year Treasury Rates[a] During the Period 1990-2006

Regression Output:

Constant (A_0)		0.0876
Std Err of Y Est		0.0070
R Squared		52.1%
No. of Observations		294
Degrees of Freedom		292
Slope (A_1)	-0.5803	
Std Err of Coef.	0.0325	
t-statistic	-21.003	

Equity Cost Estimate		Predicted Risk Premium		10-Year Treasury Rate[b]
10.9%	=	5.7%	+	5.2%
11.0%	=	5.7%	+	5.3%

Formula: Risk Premium = A_0 + (A_1 x 30-Year Treasury Rate)[c]

Sources and Notes:

_a/ Source of Data: Oregon PUC Response to NW Natural Data request in UG 132 updated with data in Phillip Cross, Rate of Return: Still an Issue at PUCs, Public Utilities Fortnightly, December 1998 and 2000 plus decisions reported by Regulatory Research Associates for 1999-2006.

_b/ Top of range: Global Insight forecast for 2009, October 2007. Bottom of range: Blue Chip Consensus forecast for first quarter 2009, October 2007.

_c/ 6-month lag between order date and Treasury interest rates adopted.

11/9/07

Portland General Electric

Exhibit 1016

Summary Table: Estimated Costs of Equity for Portland General Electric

	Estimated Equity Costs for Benchmark Utilities			Estimated Equity Costs for PGE-n/		
DCF analysis -- Table 7		11.2%			11.4%	
DCF analysis -- Table 9		11.3%			11.5%	
DCF analysis -- Table 10		10.5%			10.7%	
Risk premium -- Table 12	10.9%	to	11.2%	11.1%	to	11.4%
Risk Premium -- Table 13		11.2%			11.4%	
Risk premium -- Tables 14 & 15	10.8%	to	11.0%	11.0%	to	11.2%
Checks on ROE Estimates	10.9%	and	10.9%	11.1%	and	11.1%
Range of Equity Cost Estimates	10.5%	to	11.3%	10.7%	to	11.5%
Average Equity Cost Estimate		11.0%			11.2%	
PGE Requested ROE					10.75%	

Note:
n/ Equity Cost estimates include a 20 basis point risk premium for PGE.

11/09/07

UE ___ / PGE / 1100
NGUYEN

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Ham T. Nguyen

February 27, 2008

Table of Contents

I. Introduction and Summary

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

A. My name is Ham T. Nguyen. I am employed by PGE as a Senior Economist and am responsible for developing PGE's end-use customer load forecast. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. My testimony presents and explains the methodology and processes underlying PGE's 2009 test year forecast of 20,260 million kilowatt-hours (kWh), on a cycle-month (billing) basis, delivered to end-use customers, including deliveries to customers who opted out of PGE cost of service rates for direct access under Schedule 483.

Q. What do you conclude?

A. I project that deliveries to all end-use customers will increase from the 2007 weather-adjusted value of 19,546 million kWh to 20,260 million kWh for test year 2009. This 2009 total kWh delivery takes into account the effect on demand of anticipated higher electricity prices in 2009 from the 2007 base period prices and savings from "incremental" energy efficiency (EE) programs.

PGE Exhibits 1101, 1102, and 1103 show three different detailed kWh delivery forecasts. These three forecasts are "base" B (non-price), P (price-effect), and E (post price effect and "incremental" EE programs).

Table 1 below summarizes the kWh delivery forecast in annual percentage changes by end-use sector from 2007 through 2009.

Table 1
Percent Change in kWh Delivery from Preceding Year: 2007-2009

Sector	2007[1]	2008 (B)	2008[2] (E)	2009 (B)	2009[2] (E)
Residential	(0.7%)	1.3%	1.3%	0.1%	(0.0%)
Commercial	1.3%	1.4%	1.3%	1.2%	0.8%
Industrial	0.8%	3.9%	3.9%	5.9%	5.9%
Miscellaneous	(1.6%)	0.9%	0.9%	1.3%	1.3%
Total Retail	0.9%	1.9%	1.9%	1.9%	1.7%

1 Weather-adjusted actual
2 Post price and EE program impacts

Q. Why do you adjust your base forecast for price elasticity effects?

A. The non-price or base (B) delivery forecast does not take into explicit account the impact of electricity price changes on end-use consumption. The price-effect (P) forecast does. PGE expects customers to respond to price changes by making behavioral changes, implementing housekeeping measures and, over time, making changes to the capital stock such as appliances and equipment that would reduce energy consumption.

Q. How do you specifically account for the impact of a price change in the test year forecast?

A. We calculate the implied demand elasticity of the price model by varying price levels, (e.g., by 10%). Demand elasticity is the ratio of the percent change in demand, kWh delivery in this case, to the percent change in price. For the test year forecast, we first calculated the kWh demand change based on an assumed price change by multiplying it with the price elasticity, and then adjusted the base forecast by the demand change estimate. This is the same procedure used in previous rate cases.

Q. What price change assumptions did you make to calculate the price impact on demand?

A. In 2008, we assumed a 4.6% price decrease for residential customers and a 0.1% price increase for nonresidential customers from November 2007 prices, mostly from the return of the Residential Power Act (RPA) credit which offsets the net increase of AUT, Automatic Meter Infrastructure (AMI), Senate Bill (SB) 408, and Energy Efficiency (EE) tariffs. In 2009, we assumed prices for residential customers will be 4.3% above November 2007 levels which included the above 2008 rate changes plus this rate request. For nonresidential customers prices are assumed 5.3% above November 2007 prices.

Q. What price elasticity does PGE estimate and use in the forecast?

A. We used elasticity estimates of 0.08 for residential demand and 0.03 for nonresidential demand, the same ones that we used in previous rate proceedings, most recently in UE 180. A price elasticity of 0.08 means that if electricity prices rose an average of 10%, kWh demand would decline by 0.8%, all else equal. As we pointed out in UE 180, these elasticity estimates have remained stable since 2002. Using these estimates of elasticity and assumed price increases, the price-effect (P) forecast is about 39 million kWh or 0.2% lower than the base (B) forecast for 2009.

Q. Did you make any adjustments beyond the impact of electricity price changes to the load forecast?

A. Yes. We adjusted the forecast to account for the impact of PGE's incremental EE programs. They are based on new funding to EE programs beyond current levels, starting in mid-2008 through 2012. The Energy Trust of Oregon (ETO) developed the estimates of these "incremental savings" based on achievable measures up to 6.5 cents levelized cost. We assumed these EE savings to take effect in July 2008, ramping up gradually through 2012.

Q. How significant is the impact of these incremental EE programs savings on PGE's load forecast?

A. We estimate a total of 42 million kWh savings from these programs in the 2009 test year.

II. Model Mechanics

Q. Please summarize the process you use to develop the retail load forecast.

A. The core retail load model and the forecast process are the same as we have used in previous rate cases and regulatory filings. However, we re-estimated the model using the most current data, an extended sample period through and including November 2007. Re-estimation is the process of applying regression techniques to obtain, from the updated or extended historical data, estimates of the coefficients of the equations that constitute the model. We retained the structure (specification) but re-estimated the base model to include new information, examining for any changes in the coefficients and, if necessary, re-specifying the relevant equations. Finally, we used the most recently available forecasts of the drivers or independent variables to develop our load forecast.

Q. Are these models new or different from previous PGE load models?

A. Except for the re-estimation of the coefficients aimed to capture any behavioral or structural changes over time, the load forecast model specification remains the same as those used in previous filings with the Commission. I described in detail the theory and specification of our load model as well as our forecast processes in my previous testimonies on PGE's load forecast submitted in various regulatory proceedings, most recently in UE 180.

Q. Why do you need to re-estimate the load model?

A. To capture evolving changes in customer behavior or mode of operations, PGE re-estimates our load model to reflect the most current customer-to-energy relationships and to incorporate empirically any behavioral changes as early as possible. These relationships could change significantly in the events of a war, natural disaster, severe economic downturn or sharp price hikes. If we do not re-estimate our models to reflect such changes, the models could produce inaccurate forecasts.

Q. What sources of information do you use to forecast electricity deliveries?

A. PGE relies primarily on three sources of economic information to drive our forecast: 1) a national economic forecast, 2) state economic and unemployment forecasts, and 3) a forecast of the California economy. Global Insight (formerly the WEFA Group) provides the US economic forecast. The Department of Administrative Services, Office of Economic Analysis (OEA) provides the Oregon economic forecast (Oregon Economic and Revenue Forecast) and the Oregon Employment Department provides the state unemployment forecast. The California Employment Development Department's (EDD) provides the forecast of the California economy. These forecasts – all available in December 2007 – are the same sources of information we used to develop our load forecasts in our previous filings with the Commission.

Q. Did you make any changes to the model?

A. No. Except for the re-estimation, we made no changes to the structure of the model.

Q. What assumption did you make regarding weather variables in the forecast?

A. The accuracy of a forecast depends not only on the performance of its model but also on the performance of the independent variables driving the forecast. In our load model, this would include temperature, among other weather variables that affect energy use. For weather variables we have been using 15-year moving averages to represent forward-looking weather conditions since UE 180.

Q. How current are the data you use to estimate the model?

A. We use the most recent historical kWh deliveries and economic data to estimate the model and develop the forecast. For the development of the model in this proceeding, we used data from 1985 through November 2007 for residential equations and data from 1990 through November 2007 for nonresidential equations. The latter choice results from the limitation of NAICS-based Oregon employment data.

Q. What end-use sectors do you forecast in the model?

A. We forecast at the aggregate levels demand by residential, commercial, manufacturing (industrial) customers, and energy served under miscellaneous rate schedules. Residential customers are mostly households, but also include dwellings that PGE has connected for electrical service but are not yet occupied. Commercial customers typically are businesses providing services, such as retail and wholesale establishments, schools, hospitals, government or financial institutions. Industrial customers are manufacturing entities. They include manufacturers of paper, lumber, steel, machinery, micro-processors, computers, truck and aircraft parts, and shipyards, among others, that serve national and global markets.

In our model, we group commercial and manufacturing customers according to the NAICS definition of business segments. We develop the kWh projections for these three end-use sectors separately and then sum them together with the forecast of existing miscellaneous schedules - streetlight, irrigation, etc. - to obtain total end-use energy.

Finally, we allocate these NAICS-segment delivery forecasts into voltage-level (rate schedule) kWh deliveries using their respective proceeding-year ratios. We described in detail these sectors' model specifications and forecast processes in UE 180 testimony.

Q. How do you forecast the ultimate loads delivered to the PGE distribution system?

A. This process involves three steps: 1) aggregate cycle-based sector kWh deliveries into various voltage service levels, 2) convert cycle-based deliveries to calendar-based deliveries and 3) add transmission and distribution losses to voltage-service level kWh deliveries to calculate system load in average MW and in MW demand.

Q. What is the voltage aggregation process?

A. Different customers require different voltage levels to run their appliances or equipment. Residential, most commercial, and some industrial customers require *secondary* voltage services (less than 11,000 volts). Most industrial and some commercial customers require *primary* voltage services (between 11,000 volts and 57,000 volts). Large industrial customers require services at "transmission" voltage (equal to or greater than 57,000 volts). We prorate projected kWh deliveries to commercial and industrial customers by the most recent service-level allocation factors at the NAICS level to obtain the forecast of kWh deliveries by voltage service levels.

Q. How do you calculate the ultimate load?

A. We add transmission and distribution (line) losses to the kWh deliveries at the meter to obtain the gross (or upstream) average MW required to meet the end users' demand. For test year 2009, we apply the line loss factors based on those used in UE 180. We use monthly and annual load factors to calculate the monthly MW and annual peak MW based on the projected average MW. PGE Exhibit 1109 displays the forecast of total distribution loads in annual average MW and MW peak demand.

III. Forecast Results

Q. What are the key results of your residential forecast?

A. We project 2008 deliveries of 7,693 million kWh to 709,769 residential customers using the base model (B) and a higher forecast of 7,720 million kWh after accounting for the effects of electricity price changes and incremental EE programs (E). The assumed price decrease in 2008 drives up deliveries while incremental EE programs drive down deliveries in that year. For the test year 2009, we forecast deliveries of 7,753 million kWh (B) and 7,720 million kWh (E), to 716,469 residential customers. The assumed price increase and incremental EE programs both drive down deliveries in 2009. These delivery levels indicate 0.8% (B) and 0.0% (E) growth from 2008 to 2009, respectively, compared to an actual 0.7% growth in kWh delivery, adjusted for weather, in 2007. Both forecasts include residential outdoor lighting energy.

The forecasts include projections of 7,724 new residential connects in 2008 and 8,584 in 2009. These levels are below the 2007 total new residential connects of 11,337 due mostly to the current housing market slump. We forecast growth in the number of residential customers in both 2008 and 2009, offsetting projected declines in kWh use per customer. PGE Exhibit 1104 shows the forecast of building permits, new connects, and occupied accounts. PGE Exhibit 1105 displays the forecast of kWh use per occupied account and deliveries to residential customers in detail.

Q. What are the key results of your commercial forecast?

A. We project deliveries to commercial customers of 7,296 million kWh using the base (B) model and a forecast of 7,291 million kWh after accounting for the effect of price and incremental EE programs for 2008. For test year 2009, we forecast deliveries of 7,393 million kWh in the base (B) forecast and 7,351 million kWh in the adjusted (E) forecast. As with residential customers, we expect rising electricity prices to have an impact on kWh delivery to commercial customers, albeit to a lesser degree due to this sector's inelastic demand response, (i.e., relatively smaller nonresidential price elasticity). On the other hand, the savings from incremental EE programs in the commercial sector are larger than those in the residential sector. We forecast growth in this market segment - after accounting for price impacts and EE program savings - to continue at 1.3% in 2008 and 0.8% in 2009, similar to 1.3% growth experienced in 2007. PGE Exhibit 1106 provides the detailed forecast of deliveries to commercial customers.

Q. What are the key results of your industrial forecast?

A. We project total deliveries to industrial (manufacturing) customers of 4,697 million kWh using the base model (B) and a forecast 4,697 million kWh post price and EE savings (E) for 2008. For the test year 2009, we forecast deliveries of 4,979 million kWh (B) and 4,973 million kWh post price and EE savings (E). We expect only minimal response to electricity price changes due to the industrial sector's inelastic response and insignificant impact from incremental EE programs as little funding is devoted to this sector in both 2008 and 2009. We forecast delivery to industrial customers to increase 3.9% in 2008 and 5.9% in 2009. We included in the delivery forecast the expected completion and gradual operation of two large solar cell and panel manufacturers and expansion of one large non-solar manufacturer who are building their manufacturing plants in the Portland metro area. PGE Exhibit 1107 provides the detailed delivery forecast of the industrial sector.

IV. Direct Access Forecasts

Q. Did you make a separate forecast of delivery to Schedule 483/489 customers?

A. Yes. PGE separates the loads of customers served under PGE cost-of-service (COS) rates including variable-price (market power) purchases for customers who choose this option and those few customers who chose service under Schedule 483/489 (non-COS). Schedule 483/489 is the only service under which customers may not receive COS pricing. We pro-rated COS and non-COS loads by applying the most recent kWh shares of these customers to their respective service level or revenue class. PGE Exhibit 1110 shows a forecast of COS and Non-COS (Schedule 483/489) deliveries for test year 2009.

Q. Do you recommend a specific forecast or forecasts of test year 2009 kWh delivery to end-use customers for rate making purposes?

A. Yes. I recommend the adoption of the E (post price and EE programs) forecast of 20,260 million kWh delivery to all customers and the forecast of 18,513 million kWh delivery to COS customers for test year 2009.

V. Forecast Uncertainty

Q. How do you propose to address forecast uncertainty?

A. We can reduce uncertainty by using more current information, data and forecast drivers because conditions could and will likely change between the time PGE develops this forecast and the start of the test year.

Q. What do you propose to update and when?

A. PGE proposes that, before the close of the record of this proceeding, we update the test year delivery forecast with the most current input assumptions and, if necessary, the model. This would include not only the economic indicators and forecasts but also demand elasticity and price changes.

Q. Is there risk associated with this forecast?

A. The kWh delivery forecast we submit in this filing is our best estimate forecast. As with any estimate, actual conditions may differ from what we assume or anticipate in the forecast, rendering a different outcome.

Q. What are the drivers of the uncertainty of your forecast?

A. Our forecast depends on the stability of our model and the accuracy of input assumptions. Our model typically performs well over the *sample* period, the span over which we estimate the model, as it captures most, if not all, behaviors and relationships such as economic activities or customer response to price changes on energy use. We expect our model to perform equally well over the forecast period if these relationships remain unchanged or *stable*. If such relationships change in the test year period in response to significant events that were not anticipated or have never occurred over the historical period, our model will become outdated, or in statistical language *mis-specified*, leading to inaccurate forecasts.

The other area of uncertainty, outside of weather variances, involves input assumptions such as the economy, electricity prices, key customers' operation decisions, new customers' entry or existing customers' exit and the absence of unforeseen natural disasters, wars or geopolitical turmoil. These variables' future outcome could turn out different than anticipated, resulting in significant departure from the forecast.

Q. Are the input assumptions PGE uses to drive its forecast deterministic or subject to uncertainty?

A. All input assumptions are subject to uncertainty. PGE used as key drivers the December 2007 Global Insight and Oregon OEA *baseline* economic forecasts that could change going forward as these organizations develop newer forecasts. These economic forecasts have their own issues of uncertainty. Global Insight, for example, assigns 50% probability of occurrence to its December 2007 *baseline* U.S. economic forecast, 10% probability to its *High Scenario* (False Alarm) and 40% probability to its *Low Scenario* (Hard Landing). Previously Global Insight assigned 60%, 20%, and 20% for its *Baseline, High Scenario* and *Low Scenario* respectively in its August 2007 Outlook. The Oregon OEA uses *stochastic* techniques to develop its uncertainty band. For 2008, OEA (December 2007) forecasts total Oregon employment to grow 0.9% from 2007 in its *baseline* case, bounded by 0.2% *decline* in the low case and 1.8% growth in the high case. Finally, PGE's key customers could operate differently than planned. They could shut down plants, curtail operations, or add new capacity that we did not anticipate or include in the forecast because of their own economic or unique circumstances. We specifically included in this forecast completion and operation of two large solar-panel manufacturers who located to Oregon in 2007 and other high-tech customers' expansions. If any of these assumptions fail to materialize, deviations from the test year forecast could result.

Q. Does the current US economic weakness have an effect on your forecast?

A. Yes. Both the December 2007 Global Insight and OEA baseline forecasts anticipate a slowdown in economic growth from late-2007 to early-2008 but no decline in activities, specifically employment, and a rebound in growth by the second half of 2008. However, recent economic indicators such as declining US payroll employment, pessimistic consumer sentiment and ISM (Institute of Supply Management) services index dropping into contraction territory in January 2007 are signaling that the US economy could tip into a recession in early 2008. In fact, Global Insight has issued a new baseline forecast in February 2008 that calls for a recession for the first half of 2008, specifically predicting the US GDP (Gross National Products) to decline 0.4% in the first quarter and 0.5% in the second quarter 2008. Such an outcome would affect our 2009 test year delivery forecast in two ways: 1) a lower base as declining economic activities in 2008 will likely bring 2008 delivery levels below what we forecasted and 2) a recovery in 2009 may not be forthcoming or its rate of rebound may not be sufficient to bring up 2009 delivery levels to where we forecasted.

Q. Is weather also an area of uncertainty?

A. Yes. PGE discussed extensively in UE 180 uncertainty of the load forecast with regard to weather in terms of the *average* or the *mean* condition and the *variance* or *departure from the average* condition in the forecast year. The impact of this uncertainty, expressed as deviation from the mean, is significant because of the large impact of temperature on kWh usage. PGE estimates that one degree variation in temperature could affect (total retail) kWh usage by as much as 1.2% in peak months and as much as 0.7% on an annual basis.

Q. How much can the results vary for these areas of uncertainty?

A. The effect can be substantial if history were a guide. For example, actual kWh deliveries deviated as much as 8.5% below the 2002 test year forecast (UE 115) for a number of reasons that included the economic downturn, the aftermath of the West Coast energy crisis and the urgency it generated, the effect of the September 11 attack and the weather.

VI. Qualifications

Q. Mr. Nguyen, please describe your qualifications.

A. I received all my undergraduate and graduate education from the University of Oregon. I received my Bachelor of Arts in 1967 and Master of Science in 1972, both in Economics. I also completed all the course work and examinations for a doctoral degree in Economics, except for the dissertation.

I joined Portland General Electric Company in 1979. Prior to joining PGE, I worked as an independent consultant and later with Northwest Natural Gas Company as an economist. I oversee the development of PGE's economic and energy forecasting models and have the overall responsibility for the development of PGE's economic and energy forecasts. I am currently a member of the Governor's Council of Economic Advisors, State of Oregon, and a panelist of the Western Blue Chip Economic Forecast, Economic Outlook Center, Arizona State University. On various occasions I have served as a member of the Regional Forecast Panel, the Pacific Northwest Executive at the University of Washington and as a member of the Northwest Power Planning Council's Economic and Demand Forecasting Advisory Committees.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1101	(Non-Price) Delivery Forecast by market Segment and Service Level
1102	(Price Effect) Delivery Forecast by market Segment and Service Level
1103	(Post Price & EE) Delivery Forecast by Market Segment and Service Level
1104	Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts
1105	Forecast of Residential Use per Occupied Account and Ultimate Deliveries
1106	Commercial Deliveries Forecast by NAICS Cluster
1107	Industrial Deliveries Forecast by NAICS Cluster
1108	Forecast of Deliveries under Miscellaneous Secondary Rate Schedules
1109	Total Deliveries and Demand Forecast
1110	Forecast of Deliveries to Cost-of Service and Non-Cost-of-Service Customers

Delivery Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (Non-Adjusted) Forecast

		(in million kWh)				% Change[1]		
		2006	2007[2]	2008	2009	2007	2008	2009
1	Schedule 7	7,561	7,612	7,686	7,746	0.7%	1.0%	0.8%
2	Residential Lighting	7	7	7	7	(0.8%)	0.4%	1.5%
3	Total Residential	7,568	7,619	7,693	7,753	0.7%	1.0%	0.8%
4	Commercial[3]	7,101	7,195	7,296	7,393	1.3%	1.4%	1.3%
5	Manufacturing[3]	4,483	4,520	4,697	4,979	0.8%	3.9%	6.0%
6	Miscellaneous Customers	215	212	214	216	(1.6%)	0.9%	1.3%
7	Secondary Voltage	7,499	7,578	7,677	7,809	1.1%	1.3%	1.7%
8	Total General Service	7,714	7,790	7,891	8,025	1.0%	1.3%	1.7%
9	Primary Voltage Service	2,786	2,756	3,016	3,264	(1.1%)	9.4%	8.2%
10	Transmission Voltage Service	1,299	1,381	1,300	1,299	6.3%	(5.8%)	(0.1%)
11	Total Retail[4]	19,367	19,546	19,899	20,341	0.9%	1.8%	2.2%

1/ calculated from unrounded numbers

2/ includes actual weather-adjusted kWh through December 2007

3/ by NAICS grouping

4/ line 16 equals lines (3 + 4 + 5 + 6) and also equals lines (3 + 8 + 9 + 10); total may not match due to rounding

Delivery Forecast (Price) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity

		(in million kWh)				% Change[1]		
		2006	2007[2]	2008	2009	2007	2008	2009
1	Schedule 7	7,561	7,612	7,714	7,719	0.7%	1.3%	0.1%
2	Residential Lighting	7	7	7	7	(0.8%)	0.4%	1.5%
3	Total Residential	7,568	7,619	7,721	7,726	0.7%	1.3%	0.1%
4	Commercial[3]	7,101	7,195	7,296	7,386	1.3%	1.4%	1.2%
5	Manufacturing[3]	4,483	4,520	4,697	4,974	0.8%	3.9%	5.9%
6	Miscellaneous Customers	215	212	214	216	(1.6%)	0.9%	1.3%
7	Secondary Voltage	7,499	7,578	7,677	7,798	1.1%	1.3%	1.6%
8	Total General Service	7,714	7,790	7,890	8,014	1.0%	1.3%	1.6%
9	Primary Voltage Service	2,786	2,756	3,015	3,262	(1.1%)	9.4%	8.2%
10	Transmission Voltage Service	1,299	1,380	1,300	1,299	6.3%	(5.8%)	(0.1)%
11	Total Retail[4]	19,367	19,546	19,926	20,302	0.9%	1.9%	1.9%

1/ calculated from un-rounded numbers

2/ includes actual weather-adjusted kWh through December 2007

3/ by NAICS grouping

4/ line 16 equals lines (3 + 4 + 5 + 6) and also equals lines (3 + 8 + 9 + 10); total may not match due to rounding

Delivery Forecast (Price & Incremental EE) by Market Segment and Service Level

(at average weather)

Net of Price Elasticity and PGE Energy Efficiency

		(in million kWh)				% Change [1]		
		2006	2007[2]	2008	2009	2007	2008	2009
1	Schedule 7	7,561	7,612	7,713	7,713	0.7%	1.3%	(0.0%)
2	Residential Lighting	7	7	7	7	(0.8%)	0.4%	1.5%
3	Total Residential	7,568	7,619	7,720	7,720	0.7%	1.3%	(0.0%)
4	Commercial [3]	7,101	7,195	7,291	7,351	1.3%	1.3%	0.8%
5	Manufacturing [3]	4,483	4,520	4,696	4,973	0.8%	3.9%	5.9%
6	Miscellaneous Customers	215	212	214	216	(1.6%)	0.9%	1.3%
7	Secondary Voltage	7,499	7,578	7,672	7,765	1.1%	1.2%	1.2%
8	Total General Service	7,714	7,790	7,886	7,982	1.0%	1.2%	1.2%
9	Primary Voltage Service	2,786	2,756	3,015	3,259	(1.1%)	9.4%	8.1%
10	Transmission Voltage Service	1,299	1,381	1,300	1,299	6.3%	(5.8%)	(0.1%)
11	Total Retail [4]	19,367	19,546	19,921	20,260	0.9%	1.9%	1.7%

1/ calculated from un-rounded numbers

2/ includes actual weather-adjusted kWh through December 2007

3/ by NAICS grouping

4/ line 16 equals lines (3 + 4 + 5 + 6) and also equals lines (3 + 8 + 9 + 10); total may not match due to rounding

Residential Building Permits, New Connects, Vacancy Rates and Occupied Accounts
History and Forecast

	2006	2007[1]	2008	2009[2]
Building Permits [3]				
Single-Family	20,483	16,534	17,337	18,182
Multiple-Family	6,388	5,912	6,283	6,361
New Connects				
Single-Family	7,017	5,621	3,907	4,151
Multiple-Family	4,761	5,451	3,457	4,073
Mobile Home	214	218	240	240
Other	118	48	120	120
Total Connects	12,110	11,337	7,724	8,584
Vacancy Rates (%)				
Single-Family	4.6%	4.6%	4.5%	4.2%
Multiple-Family	9.2%	8.6%	9.1%	9.3%
Mobile Home	9.9%	9.7%	10.0%	10.0%
Number of Occupied Accounts				
Single-Family Heat	103,947	104,064	104,164	104,610
Single-Family Non-Heat	314,792	319,469	323,353	326,967
Multiple-Family Heat	151,734	154,052	154,793	155,465
Multiple-Family Non-Heat	41,339	44,678	47,081	49,277
Mobile Home Heat	28,278	28,043	27,783	27,735
Mobile Home Non-Heat	3,557	3,526	3,490	3,483
Other	5,179	5,325	5,365	5,437
Total Occupied Accounts	648,827	659,156	666,029	672,976
Total Number of Accounts [4]	691,931	701,952	709,769	716,469

1/ includes actuals through December 2007, except for building permits and connects which include actuals through November 2007

2/ identical for both base, price-effect and post-EE forecasts

3/ Oregon

4/ includes vacant accounts

Forecast of Residential Use per Occupied Account and Ultimate Deliveries

(at average weather)

Base Forecast

	2006[1]	2007[2]	2008	2009
Use per Occupied Account (kWh)[3]				
Single-Family Heat	16,931	16,790	16,808	16,791
Single-Family Non-Heat	11,157	11,140	11,153	11,136
Multiple-Family Heat	9,612	9,465	9,494	9,495
Multiple-Family Non-Heat	6,578	6,603	6,647	6,657
Mobile Home Heat	16,354	16,200	16,156	16,157
Mobile Home Non-Heat	11,619	11,797	11,749	11,726
Other	10,544	10,709	10,487	10,174
Average Use per Occupied Account	11,653	11,548	11,540	11,510
Ultimate Deliveries (millions of kWh)[4]				
Single-Family Heat	1,760	1,747	1,751	1,757
Single-Family Non-Heat	3,512	3,559	3,606	3,641
Multiple-Family Heat	1,458	1,458	1,470	1,476
Multiple-Family Non-Heat	272	295	313	328
Mobile Home Heat	462	454	449	448
Mobile Home Non-Heat	41	42	41	41
Other	55	57	56	55
Schedule 7 Deliveries	7,561	7,612	7,686	7,746
Residential Lighting	7	7	7	7
Total Base Residential Deliveries	7,568	7,619	7,693	7,753
Total Net Residential Deliveries[5]	7,568	7,619	7,720	7,720

1/ actual weather adjusted

2/ includes actual weather adjusted deliveries through December 2007

3/ base forecast

4/ base forecast

5/ price elasticity and incremental EE adjusted forecast

Commercial Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in million kWh)				% Change [1]		
	2006	2007 [2]	2008 [3]	2009 [4]	2007	2008[3]	2009[4]
Food Stores	479	486	496	500	1.3%	2.1%	0.8%
Govt. & Education	1,033	1,029	1,035	1,039	(0.5%)	0.6%	0.4%
Health Services	643	666	664	671	3.6%	(0.2%)	1.0%
Lodging	107	106	108	110	(0.6%)	2.0%	1.5%
Misc. Commercial	724	766	769	771	5.9%	0.3%	0.3%
Department Stores/Malls	374	366	374	381	(2.2%)	2.2%	2.0%
Office & F.I.R.E [5]	1,020	990	987	990	(2.9%)	(0.3%)	0.3%
Other Services	797	811	829	839	1.7%	2.3%	1.2%
Other Trade	824	830	865	875	0.7%	4.2%	1.2%
Restaurants	448	461	467	470	2.9%	1.4%	0.7%
Trans., Comm. & Utility	652	686	697	705	5.2%	1.6%	1.2%
Total Commercial	7,101	7,195	7,291	7,351	1.3%	1.3%	0.8%

1/ calculated from un-rounded numbers

2/ includes actual weather-adjusted deliveries through December 2007

3/ price elasticity and incremental EE adjusted forecast

4/ price elasticity and incremental EE adjusted forecast

5/ Finance, Insurance and Real Estate

Manufacturing Deliveries Forecast by NAICS Cluster

(at average weather)

Net of Price Elasticity and Incremental Energy Efficiency

	(in million kWh)				% Change [1]		
	2006	2007 [2]	2008 [3]	2009 [4]	2007	2008[3]	2009[4]
Food & Kindred Products	223	221	210	210	(1.1%)	(4.6%)	(0.2%)
High Tech	1,639	1,617	1,829	2,038	(1.3%)	13.1%	11.4%
Lumber & Wood	154	141	140	143	(8.6%)	(0.6%)	2.5%
Primary & Fab. Metals	526	547	566	578	4.1%	3.5%	2.2%
Other Manufacturing	621	628	666	715	1.0%	6.0%	7.4%
Paper & Allied Products	1,118	1,168	1,084	1,081	4.5%	(7.2%)	(0.3%)
Transportation Equipment	202	198	202	208	(1.9%)	2.0%	2.7%
Total Manufacturing	4,483	4,520	4,696	4,973	0.8%	3.9%	5.9%

1/ calculated from unrounded numbers

2/ includes actual deliveries through December 2007

3/ p price elasticity and incremental EE adjusted forecast

4/ price elasticity and incremental EE adjusted forecast

Forecast of Deliveries under Miscellaneous Secondary Rate Schedules

Net of Price Elasticity and Incremental Energy Efficiency

		(in million kWh)				% Change[1]		
		2006	2007[2]	2008	2009[3]	2006	2007	2008[2]
1	Secondary (Residential)							
2	Outdoor Area Lighting [4]	7.0	7.0	7.0	7.1	(0.8%)	0.4%	1.5%
3	Secondary (Commercial)							
4	Outdoor Area Lighting [4]	16.8	16.8	16.8	17.0	(0.0%)	(0.4%)	1.4%
5	Farm Irrigation et al. [6]	93.2	87.3	87.5	88.7	(6.3%)	0.3%	1.3%
6	Street and Other Lighting [7]	105.1	107.6	109.3	110.6	2.4%	1.6%	1.2%
7	Total Misc. Commercial	215.1	211.7	213.6	216.2	(1.6%)	0.9%	1.3%
8	All Misc. Schedules [8]	222.1	218.7	220.5	223.3	(1.5%)	0.9%	1.3%

1/ calculated from un-rounded numbers
2/ includes actual deliveries through December 2007
3/ identical for non-price, price-effect and post-EE forecasts
4/ existing Schedule 15R
5/ existing Schedules 15C
6/ existing Schedules 47 & 49
7/ existing Schedules 91, 92 & 93
8/ equals line 2 + line 7

Total Delivery and Demand Forecast

Net of Price Elasticity and Incremental Energy Efficiency

(at average weather)

	Million kWh[1]	Average MW[2]	Peak MW[3]
2006	19,367	2,348	3,706
2007	19,546	2,373	3,664
2008[4]	19,921	2,441	3,870
2009[5]	20,260	2,489	3,933

1/ cycle-month basis, at end-user meters; includes actual deliveries through December 2007

2/ calendar basis, delivered to PGE's distribution system weather-adjusted history to November 2007

3/ coincidental annual system peak; includes actual through December 2007, not adjusted for weather

4/ price elasticity and incremental EE adjusted forecast

5/ price elasticity and incremental EE adjusted forecast

Forecast of 2009 Deliveries to Cost of Service and Non-Cost-of-Service Customers

Net of Price Elasticity and Incremental Energy Efficiency

(in million kWh)

	Cost of Service	Non-Cost of Service[1]	Total Delivery[2]
Residential	7,719.8	0.0	7,719.8
Secondary	7,796.3	74.8	7,871.1
Primary	2,114.3	1145.0	3,259.4
Transmission	771.8	527.4	1,299.3
Lighting	110.6	0.0	110.6
Total Retail	18,512.9	1,747.2	20,260.1

1/ Schedule 483/489 deliveries including variable price option (index power) purchases

2/ totals may not add up due to rounding

UE ___ / PGE / 1200
KUNS - CODY

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Doug Kuns
Marc Cody

February 27, 2008

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Doug Kuns. I am the Manager of the Pricing and Tariffs Department within the Rates and Regulatory Affairs Department. My qualifications are described in Section VIII.

My name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department. My qualifications are described in Section VIII.

Q. What is the purpose of your testimony?

A. This testimony and accompanying exhibits demonstrate how our proposed E-18 Tariff recovers PGE's 2009 revenue requirement in a way that achieves just and reasonable prices for all our customers. In addition to estimating the overall effect on customer bills, this testimony also describes the rate design process, the revenue requirement allocation process, and the Marginal Cost Study.

Q. Please describe the projected Cost of Service rate impacts for 2009 resulting from the proposed rates.

A. Table 1 below summarizes the rate impacts for 2009 based on the rates proposed in PGE Exhibit 1201. The first column contains the estimated percentage changes in base rates. The second column contains the estimated percentage rate changes with all supplemental schedules except the Schedule 115, Low-Income Adjustment (LIA) and Schedule 108, Public Purpose Charge (PPC). The second column includes preliminary estimates of Schedule 105, Regulatory Adjustments and Schedule 126 Annual Power Cost Variance Mechanism, both expected to be effective January 1, 2009, as well as estimated prices for Schedules 109, 110, 111, and 140, all of which we expect to be effective June 1, 2008. PGE Exhibit 1202 contains additional detail for most of our schedules.

Table 1
Estimated Cost of Service Rate Impacts

	Estimated Rate Change (%) (base rates)	**Estimated Rate Change (%) (w/all supplementals)***
Schedule 7 Residential	9.5%	7.8%
Schedule 32	7.7%	5.8%
Schedule 83	7.7%	6.0%
Schedule 89	9.9%	7.9%
Overall	8.9%	7.1%

*includes all supplemental schedules except LIA & PPC.

Q. Please summarize any other proposed tariff changes in addition to updated prices.

A. The changes are listed below and explained further in the testimony:

- We propose a new Schedule 123, Sales Normalization Adjustment that we believe helps to remove the disincentive for PGE to promote energy efficiency and customer-sited renewable energy installations.
- Within Schedule 125 Automatic Update Tariff (AUT), we propose to allocate the net variable power costs in the AUT filings in a manner similar to that used to allocate the generation costs in Schedule 122 Renewable Resources Automatic Adjustment Clause. In addition, commencing in 2010, we propose to include within Schedule 125 the increase or decrease in fixed generation revenues resulting from changes in the multi-year cost of service (COS) opt-out. We explain the rationale and mechanics of this later in testimony. We also propose to allow for updates of Boardman fixed rail transportation costs within the AUT process. Finally, within Schedule 125 we propose to update the revenue sensitive cost factor to be consistent with the 2009 test year.
- Within Schedule 126 we adjust the revenue sensitive factor to be consistent with the proposed 2009 test year.

- We propose to more specifically define the calculation of the Large Nonresidential Load Shift True-Up contained in Schedule 128 Short-Term Transition Adjustment.
- We set the Schedule 120 Biglow Canyon 1 Adjustment to zero because this resource is included in the 2009 test period functionalized generation revenue requirement. This meets the requirements of the schedule's Special Condition 5 specifying that the revenue requirements of Biglow Canyon Phase 1 be updated annually.
- We propose to modify some of the Schedule 300 Miscellaneous Charges and Schedule 715 Special Conditions.

II. Overview of Rate Schedule Charges

Q. Please explain the general process used to develop proposed rates and charges in this filing.

A. We develop the rate schedule price components in a manner that:

- Builds from the unbundled revenue requirements by major functional cost category;
- Uses each rate schedule's revenue target from the rate spread analysis of unbundled costs;
- Develops rate schedule charges with reference to cost causation principles and customer impacts; and
- To the extent possible, avoids pricing that causes unnecessary switching between schedules.

Q. Please describe the basis of the charges contained in the proposed rate schedules.

A. We based the proposed rate schedules, as much as possible, on cost causation. To accomplish this, we use the following principles:

- A **Basic Charge** that reflects customer-related costs including meters and customer services such as billing and metering.
- A **Transmission and Related Services Charge** that incorporates transmission and ancillary service costs.
- **Distribution Charges** that recover peak and installed capacity costs associated with substations, subtransmission, the 13kV system, line transformers, and service laterals. For certain schedules, the Distribution Charge includes the costs of Trojan decommissioning, franchise fees, and the Customer Impact Offset (CIO).

The CIO is the method by which we limit price increases to certain schedules to two times the overall change from 2008 prices. The CIO then recovers from other customers the allocated costs that would otherwise be paid under those schedules where rate increases are so limited. Other schedules separately identify the costs of Trojan Decommissioning, franchise fees, and the CIO as system usage charges.

- A **Cost of Service (COS) Energy Charge** for each rate schedule based on that schedule's allocated production cost. This allocated cost is comprised of the costs associated with PGE-owned generation, contract purchases of energy, transmission and capacity, and market purchases and sales.
- For customers who choose an energy option other than COS, a **Short-term Annual Transition Adjustment** calculated as the difference between the applicable schedules' COS Energy Charge and the market value of the power.

III. Rate Schedule Design

Q. Please provide a brief summary of the major Cost of Service Rate Schedules.

A. There are four major Cost of Service (COS) rate schedules:

Schedule 7, Residential Service, currently consists of a monthly Basic Charge, volumetric Transmission and Distribution Charges, and a two-block energy rate.

Schedule 32, Small Nonresidential Standard Service, consists of a monthly Basic Charge, a volumetric Transmission Charge, and a two-block Distribution Charge. The Energy Charge is flat across all energy usage.

Schedule 83, Large Nonresidential Standard Service, currently applicable to all Large Nonresidential customers except for certain specialty schedules, consists of more complex charges than Schedules 7 and 32. In addition to the customer charges differentiated by delivery voltage, there is a Transmission Demand Charge based on the highest metered kilowatt (kW) reading for a 30 minute period during the monthly billing cycle. There is also a Distribution Demand Charge based on the same criteria above, and a Distribution Facility Capacity Charge based on the average of the two greatest monthly Demands within a 12-month period (Facility Capacity). The Energy Charge is flat for all energy usage.

Schedule 89, Large Nonresidential (>1,000 kW) Standard Service, schedule for customers whose Facility Capacity exceeds 1,000 kW, contains similar Transmission and Distribution Demand Charges, but we propose to continue to charge only for the 30 minute periods that occur during on-peak intervals, defined as between 6:00 a.m. and 10:00 p.m., Monday through Saturday. The Schedule 89 Distribution Facility Capacity Charge is calculated in the same manner as for Schedule 83. The Energy Charges will continue to be on- and off-peak differentiated.

Q. How did PGE develop the prices for each rate schedule?

A. We explain the development of the prices for each of the major rate schedules below. PGE Exhibit 1203, Rate Design, provides additional detail regarding how the individual prices for each schedule were designed.

Q. Please list the individual prices for Schedule 7, Residential Service.

A. The prices are summarized below:

Schedule 7
Residential Service Proposed Prices

Category	Prices
Basic Charge Single Phase	$10.00 per customer per month
Basic Charge Three Phase	$13.00 per customer per month
Transmission & Related Service Charge	2.25 mills per kWh
Distribution Charge	31.52 mills per kWh
Energy Charge first 250 kWh	50.66 mills per kWh
Energy Charge Over 250 kWh	68.41 mills per kWh

Q. Please explain how you developed these prices.

A. Although the Marginal Cost Study results suggest a **Basic Charge** of approximately $11.00, we maintain the proposed single-phase and three-phase Basic Charges at their current levels of $10.00 and $13.00 in order to mitigate bill impacts to lower usage customers.

We develop the **Transmission & Related Service Charge** directly from the allocated transmission and ancillary services revenue requirement.

We calculate the **Distribution Charge** of 31.52 mills per kWh from the allocated distribution costs and from the allocated costs not recovered by the Basic Charges. The Distribution Charge also includes the allocation of franchise fees, Trojan Decommissioning costs and a small CIO adder of 0.12 mills per kWh to offset the revenue effects of limiting increases to Schedules 47, and 49. We further discuss the CIO later in this testimony.

We developed the Schedule 7 **Energy Charges** of 50.66 mills per kWh for the first block of 250 kWh and 68.41 mills per kWh for subsequent kWh from the allocated generation revenue requirement. We propose to maintain the current block differential of 17.75 mills per kWh.

Q. Are you proposing changes to Schedule 7, Portfolio Options?

A. No.

Q. Why do you continue to advocate the pricing of fixed distribution costs on a volumetric basis?

A. Although distribution costs are primarily fixed in nature related to the installed capacity per customer, and as such should be recovered by a fixed charge or a Demand Charge, we choose to continue to endorse volumetric charges because of administrative simplicity, tradition, and because, once again, we wish to mitigate bill impacts to lower usage customers. This argument is true for all rate schedules that contain volumetric Distribution Charges. We further believe that our decoupling proposal removes a disincentive to promote energy efficiency and provides for traditional volumetric price signals to customers. Absent our decoupling proposal, we would advocate for higher customer charges to reduce the impact of recovering fixed distribution costs on a volumetric basis.

Q. Please list the individual prices for Schedule 32, Small Nonresidential Service.

A. The prices are summarized below:

Schedule 32
Small Nonresidential Service

Category	Price
Basic Charge Single Phase	$12.00 per customer per month
Basic Charge Three Phase	$16.00 per customer per month
Transmission & Related Services Charge	1.84 mills per kWh
Distribution Charge First 5,000 kWh	29.87 mills per kWh
Distribution Charge Over 5,000 kWh	5.76 mills per kWh
Energy Charge	63.56 mills per kWh

Q. Please describe how you developed the Schedule 32 prices.

A. Schedules 32 and 532 apply to Small Nonresidential customers, whose Facility Capacity is less than 30 kW. Schedule 532 (applicable to Direct Access Service) is actually a subset of Schedule 32 in that it contains some, but not all, of the cost components of Schedule 32. Small Nonresidential customers receive service at secondary voltage and for the most part do not have Demand meters. Consequently, other than the Basic Charge, all charges are expressed as a volumetric kWh charge. As with Schedule 7, the applicable costs are allocated into the Basic, Transmission, Distribution and Energy Charge categories. We maintain the Basic Charge for single- and three-phase service at $12 and $16 per month, which is close to the marginal customer-related costs. As with Schedule 7, we capture the difference between the allocated customer-related costs and the Basic Charges revenues within the Distribution Charge.

We compute the **Transmission and Related Services Charge** directly from the allocated transmission and ancillary service costs.

We retain the current Schedule 32, **Distribution Charge** blocking, with the initial block including usage up to 5,000 kWh. We set the second block for usage greater than 5,000 kWh to 3.00 mills per kWh (prior to adding the System Usage Charge) in order to provide a better transition to Schedule 83 for customers whose loads have exceeded 30 kW at least twice during the preceding 13 months. Similar to Schedule 7, we include within the Distribution Charge the costs associated with franchise fees and regulatory assets as well as the CIO adder that offsets the revenue effects of limiting the increase to certain schedules.

We set the **Energy Charge** based on the allocation of generation costs in the same manner as Schedule 7.

Finally, for the same reasons, we propose to implement a decoupling adjustment for Schedules 32 and 532 in a manner similar to Schedule 7.

Q. Briefly describe Schedule 532.

A. Schedule 532 sets out the charges associated with PGE's transmission and distribution services, but excludes energy supply and transmission costs because the customer's Energy Service Supplier (ESS) provides these services.

Schedule 532 includes the same Basic and Distribution Charges as Schedule 32, except that we increase the Basic Charge to reflect the metering required for Direct Access Service. We incorporate a Daily Price Energy Charge into Schedule 32 in order to address the potential cost impact of customers switching from Schedule 532 to Schedule 32 prior to completing at least one year of service on Schedule 532. The daily price tracks the daily market price for power and is based on the secondary voltage Daily Price option in Schedule 83.

Q. Please provide the proposed monthly prices for Schedule 83 and describe the customers to whom these prices apply.

A. Schedule 83 applies to all Nonresidential customers with Facility Capacity loads greater than 30 kW and less than or equal to 1,000 kW. Those customers whose load exceeds 1,000 kW will take service under Schedule 89, which we discuss below. We use the same approach and cost causation principles as described for Residential and Small Nonresidential service in designing these rates.

The Schedule 83 charges include more detail because Large Nonresidential customers are generally more sophisticated energy users and are more able to react to pricing signals triggered by their peak consumption. Schedule 83 integrates service to secondary and primary delivery voltages into one schedule. To the extent practicable, we base the charges on the Marginal Cost Study, with particular attention given to appropriately pricing the cost differentials between delivery voltages. The prices differentiated by delivery voltage are below:

Schedule 83
General Service 31-1,000 kW

Category	Secondary Price	Primary Price
Basic Charge Single Phase	$20.00 per customer per month	$80.00 per customer per month
Basic Charge Three Phase	$25.00 per customer per month	$80.00 per customer per month
Trans. & Related Services	$ 0.75 per kW peak Demand	$ 0.75 per kW peak Demand
Distribution Demand Charge	$ 2.13 per kW peak Demand	$ 2.13 per kW peak Demand
Facility Capacity Charge (First 30 kW)	$ 1.54 per kW Facility Capacity	$ 1.81 per kW Facility Capacity
Facility Capacity Charge (Over 30 kW)	$ 2.34 per kW Facility Capacity	$ 1.81 per kW Facility Capacity
System Usage Charge	4.19 mills per kWh	4.03 mills per kWh
COS Energy Charge	63.13 mills per kWh	61.06 mills per kWh

Q. Please describe how you developed the Schedule 83 prices.

A. The Schedule 83 **Basic Charges** differ by delivery voltage consistent with current rates. For three-phase secondary service, the Basic Charge remains at $25.00 per month in order to enable a smoother transition for Schedule 32 customers whose Demand exceeds 30 kW; this charge recovers about 70% of the marginal customer-related costs. We used this same ratio to develop the primary voltage Basic Charge of $80.00 per month. The Distribution Demand Charge recovers the remaining customer-related costs as well as any other costs either not fully recovered or more than fully recovered through the appropriate charge.

For Schedules 83 and 89, we set the **Transmission & Related Service Charge** to $0.75 per kW in order to make the pricing more consistent for customers who choose Direct Access Service under either Schedule 583 or Schedule 589. This charge results in more than a full recovery of Schedule 83 allocated costs, consequently we flow the over recovery through to the Demand Charge.

The **Distribution Charges** for Schedule 83 consist of a **Demand Charge** and a **Facility Capacity Charge**. For both secondary and primary voltage customers, we recover the costs associated with the 13 kV system and connect costs through the Facility Capacity Charge. The difference between secondary and primary voltage Facility Capacity Charges reflect the cost differences in serving the different delivery voltages for customers of equal size. For Secondary customers, we set the Facility Capacity Charge for the first 30 kW at a lower level than the Facility Capacity Charge for over 30 kW in order to once again provide a smooth transition for Schedule 32 customers who migrate to Schedule 83 because their Demand exceeds 30 kW.

The **Demand Charge** of $2.13 for both secondary and primary customers recovers the allocated revenue requirement of substations and the 115 kV system as well as any under recovery of other charges.

Because several energy options are available to Schedules 83 and 583, we separately state the **System Usage Charge** which recovers franchise fees, Trojan Decommissioning costs, and the CIO.

Q. Please describe the Schedule 83 Energy Charge options.

A. Schedule 83 customers may choose to receive energy either from PGE based on PGE's COS energy option or from one of PGE's market-based energy options. The market-based options include daily pricing based on the prices for the Mid-Columbia hub as reported by the Dow Jones Mid-Columbia Daily On- and Off-Peak Firm Pricing Index (Dow Jones), and monthly price quotes made on or around the 15th of each month. Customers may also choose to receive service from an ESS.

Customers receiving service from an ESS or from a PGE market option will continue to receive the Schedule 128, Short-Term Transition Adjustment in the same manner as they currently do. For 2009 we propose to change only the manner in which Schedule 128 Large Nonresidential Load Shift True-up is calculated. Rather than valuing the True-up based on actual post-enrollment power transactions, we propose to calculate the True-up by multiplying the load change resulting from the open enrollment windows times the difference between the forward curves used to set the Schedule 128 Transition Adjustments and an average of forward curves following the close of the windows. For the November 2009 open enrollment window we propose to use the first full week in December (i.e., December 7 through 11, 2009) to calculate the True-up. For the quarterly windows we propose to use the average curves for the first full week after the enrollment window closes.

We believe this proposed methodology provides greater transparency and removes ambiguity regarding when PGE should execute true-up transactions. It also better reflects the actual impact of the enrollment window selections by taking into account load amounts that differ from the typical wholesale power transaction lots of 25 MW transactions.

Q. What schedule is applicable to Schedule 83 customers who wish to pursue the Direct Access energy option?

A. Customers choosing the Direct Access energy option will take service under the provisions of Schedule 583. Schedule 583 pricing mirrors Schedule 83 except that it contains neither a company supplied energy price, nor a Transmission & Related Services Charge.

Q. Please provide the proposed monthly prices for Schedule 89 and describe the customers to whom these prices are applicable.

A. Schedule 89 applies to all Large Nonresidential customers whose Facility Capacity loads exceed 1,000 kW. Because of their unique characteristics we have separately identified the distribution costs for customers whose loads exceed 4,000 kW and integrated these cost differences into the Schedule 89 pricing for service to secondary, primary, and subtransmission delivery voltages. The charges are based on the Marginal Cost Study with attention to billing impacts and the cost differentials between delivery voltages. The Schedule 89 prices differentiated by delivery voltage are below:

Schedule 89 General Service Greater than 1,000 kW

Category	Secondary	Primary	Subtransmission
Basic Charge	$160.00 per month	$230.00 per month	$1,000 per month
Transmission & Related Charge	$ 0.75 per on-peak kW	$0.75 per on –peak kW	$0.75 per on-peak kW
Facility Capacity Charge First 1,000 kW	$ 2.05 per kW Facility Capacity	$1.83 per kW Facility Capacity	$1.83 per kW Facility Capacity
Facility Capacity Charge Over 1,000 kW	$ 0.61 kW Facility Capacity	$0.39 per kW Facility Capacity	$0.39 per kW Facility Capacity
Distribution Demand Charge	$ 2.18 per on-peak kW	$2.18 per on-peak kW	$1.10 per kW
System Usage Charge	4.07 mills per kWh	3.87 mills per kW	3.72 mills per kW
COS Energy Charge On-peak	68.65 mills per kWh	66.18 mills per kWh	65.19 mills per kWh
COS Energy Charge Off-peak	53.67 mills per kWh	51.71 mills per kWh	50.90 mills per kWh

Q. Please describe how you developed the Schedule 89 Charges.

A. We set the **Basic Charges** for secondary and primary voltage customers at levels that approximate the marginal-customer-related costs with any over- or under- collection captured by the Facility Capacity Charges. Although the Marginal Cost Study indicates a cost of approximately $2,100 per month, we maintain the subtransmission Basic Charge at the current $1,000 per month, in part because subtransmission voltage customers are receiving the largest increase relative to other Schedule 89 customers. The Schedule 89 Facility Capacity Charge captures the under collection.

The Transmission and Related Service Charge is calculated in conjunction with Schedule 83 for the reasons previously discussed. Because this charge is less than the allocated costs, the Facility Capacity Charge recovers the remainder.

The **Distribution Demand Charge** for both secondary and primary voltage customers reflects the marginal cost of providing substations and shared subtransmission facilities. For customers served at subtransmission voltage who supply their own substation, the Distribution Demand Charge reflects the marginal cost of the shared subtransmission system plus the cost per kW differential between connecting a customer of equal size with a 13 kV feeder or a feeder at 115 kV. This differential of 0.13 cents is added to the Distribution Demand Charge to equalize the Facility Capacity Charge for primary voltage and subtransmission voltage delivery.

The Facility Capacity Charge for Schedule 89 customers has two blocks; one for the first 1,000 kW, and the second for billing kW greater than 1,000 kW. The first block facilitates the migration of customers from Schedules 83/583, while the second block captures the remaining facilities-related revenue requirements of Schedule 89 customers. Both Facility Capacity Charge blocks reflect the marginal cost difference between providing service at secondary or primary voltage service. As mentioned above, we set the Facility Capacity Charge for subtransmission voltage customers equal to that of primary voltage customers and flow any cost difference to the subtransmission voltage Demand Charge.

The **COS Energy Charge** option for Schedule 89 is on- and off-peak differentiated. Daily and Monthly Price options are also available similar to those described for Schedule 83. Customers who wish to pursue the Direct Access Energy Option will take service under Schedule 589. As with Schedules 83/583, Schedules 89/589 separately identify the System Usage Charge.

Q. Describe the development of charges for the remaining rate schedules.

A. The remaining proposed rate schedules provide service to lighting and irrigation customers and are discussed below:

We structure **Schedule 15, Outdoor Area Lighting Standard Service**, charges in the same manner as the current rate schedule. The Monthly Charge contains all of the allocated costs based on the specific kWh usage by luminaire. Schedule 515 provides this customer class with Direct Access Service charges. PGE Exhibit 1206 includes a summary of the Area Light Cost Study.

Schedule 47, Irrigation and Drainage Pumping Small Nonresidential Standard Service, applies to Small Nonresidential customers whose Demand does not exceed 30 kW. We retain both the monthly Basic Charge at $25.00 per month for the six summer months only, and the blocked Distribution Charge. Schedule 47 customers may take Direct Access Service under Schedule 532. As discussed later in this testimony, consistent with past PGE practice and past Commission decisions, we have held the increase in this schedule to two times the average base rate increase of 8.9%; otherwise the proposed rate increase from 2008 prices would be approximately 39%.

Schedule 49, Irrigation and Drainage Pumping Large Nonresidential Standard Service, is similar to Schedule 47, but applies to customers larger than 30 kW. We retain the Basic Charge of $30 per month, summer months only. Similar to Schedule 47, we continue to block the Distribution Charge. Schedule 549 states the Direct Access charges for these customers. These customers are also eligible for Direct Access Service on Schedule 583. We limited the Schedule 49 price increase to two times the average increase instead of the approximate 56% indicated by cost-based pricing.

Schedules 91/591, Street and Highway Lighting Standard Service, provides municipalities with outdoor lighting service. These schedules are similar in structure to Schedule 15. Each service option monthly rate includes the applicable unbundled costs, based on the monthly kWh usage of the particular type of light.

Schedule 92, Traffic Signals Standard Service, is an energy-only rate for un-metered traffic control devices in systems with at least 50 intersections. We retain the energy-only nature of the rate.

Schedule 592, Traffic Signals Direct Access Service, provides the Direct Access-related energy-only based charge for this specialty service. Schedules 92/592 remain grandfathered services closed to additional governmental agencies.

Schedule 93, Recreational Field Lighting Standard Service, rate design maintains the Basic Charge of $30 per month, with Distribution and Transmission Charges recovered on a volumetric basis.

Schedule 94 Communication Devices Electricity Service Rider is an energy-only based charge that mirrors Schedule 92.

Q. Please describe the Area and Streetlighting Cost of Service Study.

A. Streetlighting and Area Lighting prices include the costs of investment and maintenance in addition to the Transmission, Distribution and production–related charges that apply to all other schedules. We analyze the investment and maintenance cost components separately. For the investment component, we used the historical investment rates determined in UE 180 to estimate the total revenue requirement associated with our investment in Streetlighting and area lighting equipment for the 2009 test period. For the maintenance component, we estimate the expected cost of maintaining each type of streetlight equipment based on current costs and anticipated levels of maintenance activity.

PGE Exhibit 1206 summarizes the results of this study. This Exhibit details the energy charges, fixed charges, total charges and total revenues for both Area and Street lighting.

Q. Why and how do you limit the amount of increase to some rate schedules?

A. The pricing for Schedules 47 and 49 is established at rates that are significantly less than the cost to serve. If we were to move these schedules to fully cost-based rates, they would experience significantly greater rate increases than average. This issue has existed for quite some time for Schedules 47 and 49. Over time, by successively pricing these schedules at a multiple of the average increase, we hope to move these schedules closer to cost of service while gradually sending the appropriate price signal.

We increase the System Usage Charges of the remaining schedules to offset the effect of the price mitigation efforts described above. PGE Exhibit 1203 shows the development of this offset.

Q. Please describe the proposed changes to Schedule 300 and Schedule 715.

A. In order to better reflect costs we propose to increase the Field Visit Charge, and the Credit Related Reconnection Rates. The proposed charges provide a better price signal to those customers who cause the Company to incur these costs. The Pricing work papers summarize the cost basis for these changes.

Schedule 715, Electrical Equipment Services is modified to reflect the proposed "above the line" treatment of costs and revenues as described in PGE Exhibit 600.

IV. Development of Retail Prices

Q. What basic approach did PGE use to establish rates and charges?

A. We take two major steps in establishing rates and charges. First, we allocate the revenue requirements for a function such as transmission or distribution for each proposed rate schedule based on a relevant allocation method. This step is called *cost allocation or rate spread*. Second, we design specific rates and charges based on the allocated target revenue level and marginal costs for each rate schedule, tempered for rate impacts.

Q. What is the source of the unbundled or functionalized, revenue requirements?

A. The unbundled revenue requirements, from PGE Exhibit 1204 Allocation of Costs to Customer Classes, provide the inputs for the rate spread and design process. The unbundled costs do not include any costs or credits for supplemental adjustment schedules such as the Schedule 102, Regional Power Act Exchange Credit.

Q. How do you determine the unbundled ancillary service costs?

A. We impute a value of $5.6 million for the ancillary services revenue requirement by applying Schedules 1 through 3 of our Open Access Transmission Tariff (OATT) to our 2009 projected 12 coincident peak load. We remove this imputed revenue requirement value from the production function revenue requirement and then spread it to individual rate schedules in the same manner as the generation revenue requirement.

Q. Please summarize the results of the cost allocation or rate spread process.

A. A summary of the cost allocation process for Schedules 7, 32, 83, and 89 is contained in the table below. Rather than list all seven functional unbundling categories, we combine some categories for ease of presentation. For example, we combine transmission and ancillary services together because we put these two together when setting prices; we also place

Metering, Billing, and Other Consumer Services into one category, Customer. We include franchise fees, regulatory assets and the Schedule 129 Long-Term Transition Cost Adjustment within Distribution.

Summary of Rate Spread to Selected Schedules Cycle Basis ($000)

Schedule	Production	Distribution	Transmission & Ancillary	Customer	Total
7	$490,749	$241,618	$17,334	$86,559	$836,259
32	95,343	43,566	2,767	10,668	152,344
83	360,442	97,068	11,012	4,120	472,642
89	199,980	45,052	5,453	406	250,891
System	$1,164,024	$447,723	$36,985	$103,058	$1,751,790

PGE Exhibit 1204 provides more detailed results for all of the Rate Schedules.

Q. How do you allocate the production revenue requirement to individual rate schedules?

A. Similar to UE 180, we allocate the production function based on each schedule's marginal cost, which we define as the cost of meeting each Schedule's energy requirements with market purchases delivered to the meter. PGE Exhibit 1204 provides the detailed calculations for each rate schedule and also contains the allocations for all other functional revenue requirements.

Q. Please explain how you allocate the transmission revenue requirements and the ancillary services revenue requirements.

A. Consistent with FERC methodology, we allocate the transmission revenue requirement of $31.4 million by the percent contribution of each rate schedule to the system's monthly average coincident peak (12CP). We use only the projected Cost of Service contributions to system peak because we credit the transmission revenue requirement by an amount equal to the direct access billing determinants times our current OATT rate. We allocate the ancillary services revenue requirement according to the allocation of the production revenue requirement.

Q. How do you allocate the distribution revenue requirement?

A. We allocate the distribution revenue requirement of $379.5 million using an equal percent of marginal costs methodology. To do so, we multiply the unit marginal cost by the applicable usage for each rate schedule to arrive at marginal revenues. We then compare the total marginal revenue from all schedules to the distribution revenue requirement and adjust the marginal revenue on an equal percent basis to achieve the revenue requirement. We allocate franchise fees on a revenue basis and Trojan Decommissioning on an equal cents per kWh basis adjusted for delivery voltage. We allocate the Schedule 129, Long-Term Transition Cost Adjustments on a volumetric basis to Schedule 83 and 89, the schedules eligible to receive the adjustment. In UE 180, we allocated the Schedule 129 Adjustments to all Large Nonresidential Customers, even those that were not eligible to participate. We believe that our current allocation is more reflective of cost causation and is more equitable. Should there be additional participation in the Schedules 483/489 Cost of Service Opt-Out during the September 2008 enrollment process, we will update the COS load forecast and the net variable power costs used in setting base energy rates as well as the Schedule 129 Long-Term Transition Cost Adjustments. This will ensure that PGE projects the correct COS load requirements and accompanying production costs.

Q. How do you allocate the customer service revenue requirement?

A. Similar to the allocation of distribution costs, we allocate the customer service revenue requirements on an equal percent of marginal cost basis.

V. Marginal Cost of Service Study

Q. Briefly describe the purpose of a Marginal Cost Study.

A. Since the mid-1970s, Oregon utilities have used Marginal Cost Studies for a number of purposes. In this case, PGE uses its Marginal Cost Study to guide the allocation of the distribution system revenue requirements in the rate spread process and to price PGE's unbundled services. The study's results are summarized in Table 8 of PGE Exhibit 1205.

Q. Please summarize the distribution components of the Marginal Cost Study.

A. The following categories are used to differentiate distribution marginal investment: subtransmission, substations, 13 kV feeders, connect costs, and meters.

Q. How did you calculate the marginal unit costs of subtransmission and substation investment?

A. We calculate marginal subtransmission and substation investment by summing investment for the five-year period 2005-2009, annualizing this investment and then dividing by the growth in system non-coincident peak. For substation marginal investment costs, we exclude the loads for customers served at subtransmission voltage because these customers supply their own substation. Tables 1 and 2 of PGE Exhibit 1205 summarize this portion of the study.

Q. How did you calculate the marginal unit feeder costs?

A. We estimate distribution feeder unit costs by selecting feeders that are representative of the company's system and estimate the costs in 2009 dollars of rebuilding these feeders. We then annualize these costs and express them on a per kW basis for both single- and three-phase customers by dividing by the estimated peak loadings of the customers on the selected feeders. For customers greater than four MW who are typically on dedicated feeders, we estimate the marginal feeder costs as the average distance between the substation and the customer-owned facilities. Because new customers on dedicated circuits typically have a redundant feeder, we multiply this average distance by two, resulting in a per-customer average of 6,000 feet of dedicated feeders. We then annualize the marginal costs of rebuilding these feeders in today's dollars and express them as a per-customer cost. Table 3 of PGE Exhibit 1205 summarizes the marginal cost of distribution feeders.

Q. Please describe marginal connect costs and how you calculate the unit costs.

A. We calculate marginal connect costs by estimating the cost of providing the average customer with a service lateral and a line transformer (secondary delivery voltage only) as well as the service design costs and any wire costs not captured in the feeder portion of the study. For smaller customers, such as those on Schedules 7 and 32, we estimate the average number of customers on a transformer in order to calculate appropriately their connect costs. For customers served at subtransmission voltage, we calculate connect costs as the average distance from the point at which they connect into the subtransmission system to the customers substation multiplied by the average cost per mile to provide service in 2007 dollars. After expressing the connection costs in 2009 dollars, we annualize the figure. Table 4 of PGE Exhibit 1205 summarizes the marginal connect costs by rate schedule.

Q. Please describe how you calculate the marginal costs of meters.

A. We calculate marginal meter costs as the newly installed costs of providing meters to each rate schedule and then apply an annual carrying charge. Table 5 of PGE Exhibit 1205 summarizes the meters' marginal cost.

Q. How do you allocate Marginal Distribution O&M to each Rate Schedule?

A. We allocate test-period Distribution O&M by distribution category to the rate schedules in proportion to each schedules' usage times its marginal capital cost. Table 6 of PGE Exhibit 1205 provides the details of this allocation and the final distribution marginal costs by distribution category.

Q. What is contained in Table 7 of Exhibit 1205?

A. Table 7 details the marginal costs of metering data, billing, and customer services functions. The metering data marginal costs consist of the 2009 meter reading expenses and general support expenses. The billing function marginal costs consist of projected billing and collection-related O&M. The other consumer services marginal costs contain the traditional serve and respond functions.

Q. Have you prepared a marginal cost summary table?

A. Yes. Table 8 of PGE Exhibit 1205 summarizes the marginal costs in this study for all distribution and customer cost categories.

VI. Schedule 125 Changes

Q. Please explain why and how you propose to change the allocation of the net variable power costs contained in the AUT filings.

A. We believe that our current method of calculating Schedule 125 prices, while simple and easy to understand, could more accurately reflect cost causation. Similar to the methodology stipulated to in UM 1330, we therefore propose to allocate changes in future levels of AUT net variable power costs (NVPC) adjusted for revenue sensitive costs to each rate schedule on an equal percent of generation revenue using the applicable schedule's forecasted energy and the schedule's COS energy charge. PGE Exhibit 1207 pages 1 and 2 contain example calculations of this allocation.

Q. Please describe other proposed changes to Schedule 125.

A. Within the AUT process we propose to more explicitly recognize the potential effects that multi-year COS opt-out customers have on other customers due to their unique pricing options. Specifically, we propose to incorporate into the AUT process the changes in fixed generation revenues resulting from changes in Schedules 483 and 489 participation levels relative to the most recent general rate case. Because the multi-year COS opt-out available to Schedules 83 and 89 is a separate process from traditional ratemaking dockets (e.g., Schedule 125 AUT), it has the potential to create large deviations in load that may cause both large deviations in unit net variable power costs as well as large deviations in recovery of fixed generation costs.

Q. Can you please provide some examples?

A. Yes. To illustrate, we currently have about 156 MWa served on the three-year COS opt-out which is eligible to return to PGE service in 2010. In 2009, we expect to initiate the AUT process that per the Schedule 483 and 489 tariff provisions for 2010 will include the loads of those returning customers. With current market forward prices significantly higher than embedded unit net variable power costs, should the net participation level in the multi-year COS opt-out decrease, all customers will potentially bear the burden of the resulting increase in unit net variable power costs. Under our proposal, this increase in unit NVPC would be mitigated by the fixed generation revenues of the returning load. However, under the current provisions of Schedule 125, other customers would not experience the benefits of additional fixed generation revenue contributions from the returning loads, but would bear the resulting increase in unit NVPC. The converse applies should there be increased participation during the 2010 multi-year option window in September 2009. Our proposed change to Schedule 125 would address this issue by offsetting 1) unit NVPC changes due to participation in multi-year COS opt-outs against 2) the fixed generation revenues (or lack thereof) associated with participation in multi-year COS opt-outs.

Q. What specifically do you propose regarding these potentially large load deviations within the Schedules 125 construct?

A. We propose to include the increase or decrease in Schedule 483 and 489 fixed generation revenues as either an offset to NVPC (net load returns to COS pricing) or an increase to NVPC (net load departs COS pricing) and spread these amounts to each schedule in the manner discussed above. PGE Exhibit 1207 pages 3 and 4 contain some example calculations that demonstrate the proposal. Referencing page 3 of this exhibit, the first example assumes that all load eligible to return to COS pricing does so. In this example, one where market prices are $25/MWh higher than embedded unit NVPC, the level of NVPC increases by about $91 million. However, by taking into account the fixed generation revenues from the returning load, this impact is mitigated by approximately $24.2 million. The resulting net price impact taking into account loads is an increase of about $14.8 million. The second example also on page 3 of PGE Exhibit 1207 demonstrates that all else equal, should market prices be $15/MWh higher than embedded NVPC, the level of NVPC increases by approximately $77.6 million. This is again offset by the $24.2 million fixed revenue contribution from the returning load and the net result is a price increase of less than $1.0 million.

Page 4 of PGE Exhibit 1207 demonstrates the converse situations of page 3, therefore situations where instead of increased returning load, eligible customers continue to access multi-year direct access pricing in greater numbers such that the 300 MWa limit is approximately reached. Once again, the NVPC changes are mitigated by the effect of fixed generation revenue changes attributable to the multi-year COS opt-out.

Q. Why is this proposal reasonable?

A. Currently, all customers bear risk that multi-year direct access movement (to or from PGE COS pricing) will impact unit NVPC recovered from PGE COS customers. However, the mitigating impact of changes in fixed generation revenues is not similarly tracked. Our proposal allows for these two elements of PGE's COS energy charge to be treated symmetrically and will lead to more stable rate effects from direct access changes over time.

VII. Sales Normalization Adjustment Mechanics

Q. Please summarize the Sales Normalization Adjustment (SNA) contained in Schedule 123 applicable to Schedules 7 and 32.

A. For Schedules 7 and 32, Schedule 123 compares actual weather-adjusted distribution, transmission, and fixed generation revenues that are collected on a volumetric basis with those that would be collected with a fixed per customer charge. The difference is accumulated in a balancing account and refunded or collected over a future period. Thus, PGE will receive revenues as if it had flat distribution charges of $45.59 per month for Schedule 7 customers and $69.10 for Schedule 32 customers while customers on these schedules will continue to be billed on a volumetric basis.

Q. How did you derive the per customer monthly charges?

A. We divided the total revenues from distribution, transmission, and fixed generation charges for the 2009 test period by the number of average customers for the period and divided by twelve. PGE Exhibit 1208, page 1 provides the detail of these calculations as well as the volumetric rate associated with the fixed costs subject to the SNA.

Q. Can you please provide example calculations of this Sales Normalization Adjustment?

A. Yes. PGE Exhibit 1208 page 2 provides an overview of the application of the SNA over time for Schedule 7 Residential customers. The exhibit also shows the estimated rate impact given the assumed annual change in energy use per customer.

Our example breaks the SNA calculation into three computational steps and illustrates how the SNA process operates from 2009 (the base year) through 2013 to identify the dollar amounts to recover (or refund). The example assumes residential kWh use per customer is reduced due to energy efficiency efforts equal to 6 average megawatts within the residential sector with use per customer otherwise static over time. Using the three computational steps of 1) revenues from a fixed cost rate per customer, 2) revenues from the volumetric rates that recover fixed costs, and 3) the resulting revenue difference between steps 2 and 3, one can see that the rate impact year over year is relatively modest. The cumulative impact is also relatively modest.

Q. Do you propose to limit the annual rate impact?

A. Yes. We propose that the net rate increase not exceed more than 2% of net rates in effect at the time of the Schedule 123 rate revision. If the amount is greater than 2%, the rates will be adjusted to the 2% limit. Our proposed balancing accounts provide for the inclusion of any carry-over amount in future Schedule 123 revisions. The 2% limit will be determined for the applicable schedules separately from the schedules to which the Lost Revenue Recovery (LRR) is applicable. The 2% rate increase cap acts as a "circuit breaker" to minimize the risk that the SNA will result in bill impacts greater than 2% in any particular year.

Q. Please summarize the Lost Revenues Component of Schedule 123.

A. The LRR component of Schedule 123 is a limited revenue recovery mechanism tied to the reduced kWh sales resulting from incremental energy efficiency savings generated through the Energy Trust of Oregon (ETO) programs directed to nonresidential customers other than Schedule 32. The LRR applies to PGE nonresidential customers other than Schedule 32 whose load does not exceed one average megawatt at a Point of Delivery during the prior calendar year and those nonresidential customers who qualify as a Self-Directing Customer.

The LRR reflects the amount of energy efficiency savings reported by the ETO attributable to the results of incremental energy efficiency funding supplied by the ETO to the applicable customers. Lost Revenues are equal to the reduction in transmission, distribution, and fixed generation revenues. Schedule 123 includes the Lost Revenue rate of 3.520 cents/kWh to which the energy efficiency kWh savings are applied to yield the lost revenue amount.

Q. What is incremental energy efficiency funding?

A. Incremental energy efficiency is funding supplied to the ETO in addition to that provided through Schedule 108, Public Purpose Charge. PGE has separately proposed incremental energy efficiency funding in Advice 07-25 through a new schedule, Schedule 109.

Q. How did you calculate the Lost Revenue Rate?

A. We calculated the lost revenue rate of 3.520 cents/kWh as the sum of applicable nonresidential transmission, distribution, and fixed generation revenues divided by the applicable energy. For some schedules such as irrigation and lighting the transmission and distribution charges are volumetric, while for Schedules 83 and 89 they are demand-based. To calculate the Schedule 89 portion of lost revenues we used the billing determinants of those customers who are between one and four megawatts as a proxy for the one average megawatt criteria. Because we have incorporated into the 2009 test period an estimate of the reduction in kWh resulting from the incremental energy efficiency funding under proposed Schedule 109, lost revenues for 2009 could be negative if kWh savings are less than projected.

Q. Please explain how the "load-based" decoupling alternative to Lost Revenue Recovery discussed in PGE Exhibit 100 would operate.

A. Although we do not propose specific tariff language in this filing, an alternative to the Lost Revenue Recovery mechanism proposed in Schedule 123 is a "load-based" decoupling adjustment. The load-based approach uses a similar fixed cost rate (we exclude Schedule 89 in the example provided in the Pricing work papers) as the LRR. This rate includes fixed generation, transmission, and distribution costs. In order to determine the annual adjustment amount, the fixed cost volumetric rate is applied to the difference between projected and actual loads for each calendar year during which the mechanism operates. The resulting dollar amount then accrues to the balancing account to be either refunded or recovered from customers at a future time. Differences between projected and actual loads are determined by subtracting the projected loads for a particular year from the actual loads in that year. Projected loads use the test period load forecast from PGE's most recent general rate case adjusted for the load growth percentage contained in the PGE's most recent Integrated Resource Plan.

VIII. Qualifications of Witnesses

Q. Mr. Kuns, please state your educational background and qualifications.

A. I graduated from Linfield College in 1973 with a Bachelor of Arts in Economics. I received a Master in Business Administration degree from Claremont Graduate School.

In 1979, I joined PGE in the Rates and Regulatory Affairs Department and have held various positions in the regulatory, marketing, and planning areas. My current position is Manager of Pricing and Tariffs.

Q. Mr. Cody, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization.

Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$10.00		
Three Phase Service	$13.00		
Transmission and Related Services Charge	0.225	¢ per kWh	(I)
Distribution Charge	3.152	¢ per kWh	
Energy Charge			
Standard Service			
First 250 kWh	5.066	¢ per kWh	
Over 250 kWh	6.841	¢ per kWh	
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)			
On-Peak Period	11.778	¢ per kWh	
Mid-Peak Period	6.841	¢ per kWh	
Off-Peak Period	3.928	¢ per kWh	(I)
First 250 kWh block adjustment	(1.775)	¢ per kWh	
Nonstandard Metering Charge (applicable to TOU)			
Single Phase meter	$1.00		
Three Phase meter	$4.25		

* See Schedule 100 for applicable adjustments.

SCHEDULE 15
OUTDOOR AREA LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer notifies the Company of the burn-out.

MONTHLY RATE

Included in the service rates for each installed luminaire are the following pricing components:

Transmission and Related Services Charge	0.125	¢ per kWh	(I)
Distribution Charge	3.124	¢ per kWh	(R)
Cost of Service Energy Charge	5.857	¢ per kWh	(I)

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate [1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$11.69 [2]	(I)
	400	21,000	147	19.18 [2]	
	1,000	55,000	374	40.71 [2]	
HPS	70	6,300	30	8.20 [2]	
	100	9,500	43	9.48	
	150	16,000	62	11.24	
	200	22,000	79	13.24	
	250	29,000	102	15.39	
	310	37,000	124	18.13 [2]	
	400	50,000	163	20.97	
Flood, HPS	100	9,500	43	9.89 [2]	
	200	22,000	79	13.33 [2]	
	250	29,000	102	15.70	
	400	50,000	163	21.27	(I)
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	9.06	(N)
	100	9,500	43	10.40	(I)
	150	16,500	62	12.43	
Special Acorn Type, HPS	100	9,500	43	13.28	
HADCO Victorian, HPS	150	16,500	62	14.70	
	200	22,000	79	16.29	
	250	29,000	102	18.49	
Early American Post-Top, HPS Black	100	9,500	43	10.36	
Special Types					
Cobrahead, Metal Halide	175	12,000	71	12.27	
Flood, Metal Halide	400	40,000	156	20.63	
Flood, HPS	750	105,000	285	34.87	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[1]	
Special Types (Continued)					
HADCO Independence, HPS	100	9,500	43	$12.50	(I)
	150	16,000	62	14.24	
HADCO Capitol Acorn, HPS	100	9,500	43	17.21	
	150	16,000	62	18.96	
	200	22,000	79	20.50	
	250	29,000	102	22.60	
HADCO Techtra, HPS	100	9,500	43	19.96	
	150	16,000	62	21.71	
	250	29,000	102	32.11	
KIM Archetype, HPS	250	29,000	102	19.95	
	400	50,000	163	25.32	
Holophane Mongoose, HPS	150	16,000	62	13.55	
	250	29,000	102	17.28	
	400	50,000	163	22.87	(I)

Rates for Area Light Poles

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$5.98	
	55 or less	7.51	
Wood, Painted for Underground	35 or less	6.99[2]	
Wood, Curved Laminated	30 or less	8.68[2]	(I)
Aluminum, Regular	16	7.40	
	25	12.03	(I)
	30	13.03	
	35	14.33	
Aluminum, Fluted Ornamental	14	14.07	(I)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lights Poles[1] (Continued)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Aluminum Davit	25	$12.43	(I)
	30	13.25	
	35	14.65	
	40	17.88	
Aluminum Double Davit	30	15.95	
Aluminum, HADCO, Fluted Ornamental	16	13.47	
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	25.16	
Concrete Ameron Post-Top	25	29.74	
Fiberglass Fluted Ornamental; Black	14	8.22	(I)
Fiberglass, Regular			
Black	20	5.20	
Gray or Bronze	30	6.97	(I)
Other Colors (as available)	35	9.48	
Fiberglass, Anchor Base Gray	35	15.17	
Fiberglass, Direct Bury with Shroud	18	7.87	(I)

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$12.00		
Three Phase Service	$16.00		
Transmission and Related Services Charge	0.184	¢ per kWh	(R)
Distribution Charge			
First 5,000 kWh	2.987	¢ per kWh	(I)
Over 5,000 kWh	0.576	¢ per kWh	
Energy Charge			
Standard Service	6.356	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)			
On-Peak Period	10.812	¢ per kWh	
Mid-Peak Period	6.356	¢ per kWh	
Off-Peak Period	3.604	¢ per kWh	(I)
Nonstandard Metering Charge (applicable to TOU)			
Single Phase meter	$2.35		
Three Phase meter	$4.25		

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

DAILY PRICE

The Daily Price, applicable with Direct Access Service, is available to those Customers who were served under Schedule 532 and subsequently returned to this schedule before meeting the minimum term requirement of Schedule 532. The Customer will be charged the Daily Price and Nonstandard Metering charges of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index)
- plus 0.226¢ per kWh for wheeling (R)
- times a loss adjustment factor of 1.0834

If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. Customers served under this schedule may at any time notify the Company of their intent to choose Direct Access Service. Notification must conform to the requirements established in Rule K.

2. Customers must enroll to receive service under any portfolio option. Customers may initially enroll or make one portfolio change per year without incurring the Portfolio Enrollment Charge as specified in Schedule 300.

SCHEDULE 38
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY STANDARD SERVICE (COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00		
Transmission and Related Services Charge	0.099	¢ per kWh	(I)
Distribution Charge	3.875	¢ per kWh	
Energy Charge**			
On-Peak Period	7.097	¢ per kWh	
Off-Peak Period	5.637	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 38 (Concluded)

DIRECT ACCESS DEFAULT SERVICE

A Customer returning to Schedule 38 service before completing the term of service specified in Schedule 538, must be billed at the Daily Price for the remainder of the term. This provision does not eliminate the requirement to receive service on Schedule 81 when notice is insufficient. The Daily Price under this schedule is as follows:

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Quarterly Election Enrollment Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Secondary Delivery Voltage	1.0834

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. Service under this schedule will begin on the first day of the Customer's regularly scheduled Billing Period.

2. In no case will the Company refund a Customer by retroactively adjusting the rate at which service was billed prior to the date the Customer begins service on this schedule.

3. Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 49% on-peak and 51% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

TERM

Service will be for not less than one year or as otherwise provided under this schedule.

SCHEDULE 47
SMALL NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$25.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.208	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand	4.855	¢ per kWh	
Over 50 kWh per kW of Demand	2.855	¢ per kWh	
Energy Charge***	6.085	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Summer Months**	$30.00		
Winter Months**	No Charge		
Transmission and Related Services Charge	0.205	¢ per kWh	(I)
Distribution Charge			
First 50 kWh per kW of Demand	3.276	¢ per kWh	
Over 50 kWh per kW of Demand	1.276	¢ per kWh	
Energy Charge***	6.118	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 30 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$160.00	$230.00	$1,000.00	
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.75	$0.75	$0.75	(I)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	
Over 1,000 kW	$0.61	$0.39	$0.39	(I)
per kW of monthly On-Peak Demand	$2.18	$2.18	$1.10	(R)
Generation Contingency Reserves Charges				
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.407 ¢	0.387 ¢	0.372 ¢	(R)(I)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.226¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, plus losses. **(R)**

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:*

Transmission and Related Services Charge
per kW of Daily Economic Replacement Power (ERP)
On-Peak Demand per day $0.029 (I)

Daily ERP Demand Charge

	Delivery Voltage: Secondary and Primary	Delivery Voltage: Subtransmission	
per kW of Daily ERP Demand during On-Peak hours per day**	$0.085	$0.043	(R)

System Usage Charge
per kWh of ERP 0.372 (I)

Transaction Fee
per Energy Needs Forecast (ENF) $50.00

Energy Charge*
per kWh of ERP See below for ERP Pricing

* See Schedule 100 for applicable adjustments.
** Peak hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ENF Options for ERP (Continued)

The Daily ENF pre-scheduling protocols will conform to the standard practices, applicable definitions, requirements and schedules of the WECC. Pre-Schedule Day means the trading day immediately preceding the day of delivery consistent with WECC practices for Saturday, Sunday, Monday or holiday deliveries.

ERP Pricing

The following ERP Energy Charges are applied to the applicable hourly ENF and summed for the hours for the monthly billing:

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported. (R)

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.226¢ per kWh for wheeling, plus losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer's submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place. (R)

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.226¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. (R)

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing (Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

On-peak hours (Heavy Load Hours, HLH) are between 6:00 a.m. and 10:00 p.m. PPT (hours ending 0700 through 2200), Monday through Saturday. Off-peak hours (Light Load Hours, LLH) are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all hours Sunday.

Losses will be included by multiplying the ERP Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 75 Baseline Energy.

IMBALANCE ENERGY SETTLEMENT

Imbalance Settlement Amounts are bill credits or charges resulting from hourly Imbalance Energy multiplied by the applicable hourly Settlement Price and summed for all hours in the billing period. Imbalance Energy is the kWh amount determined hourly as the deviation between Actual Energy for such hour and the ENF for such hour (i.e., Imbalance Energy = Actual Energy less ENF).

For any Imbalance Energy in any hour up to 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive Imbalance Energy (where Customer receives more ERP than the ENF), the Imbalance Energy multiplied by the Settlement Price of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 0.226¢ per kWh for wheeling, plus losses. **(R)**
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index plus 0.226¢ per kWh for wheeling, plus losses. **(R)**

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

For any Imbalance Energy in any hour in excess of 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 10%, plus 0.226¢ per kWh for wheeling, plus losses. **(R)**
- For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index, less 10%, plus 0.226¢ per kWh for wheeling, **(R)** plus losses.

The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule N Curtailment Plan and Rule C (Section 2).

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Dow Jones Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. **(R)**

Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

Losses will be included by multiplying the Energy Charge Daily Rate by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 1,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage Secondary	Delivery Voltage Primary	
Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00	$80.00	(R)
Transmission and Related Services Charge			
per kW of monthly Demand	$0.75	$0.75	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 30 kW	$1.54	$1.81	(R)
Over 30 kW	$2.34	$1.81	(I)(N)
per kW of monthly Demand	$2.13	$2.13	(I)(R)(D)
Energy Charge			
Cost of Service Option per kWh	6.313 ¢	6.106 ¢	(I)
See below for Daily or Monthly Pricing Option descriptions.			
System Usage Charge			
per kWh	0.419 ¢	0.403 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON COST OF SERVICE OPTIONS

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Quarterly Election Enrollment Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

Monthly Fixed Price Option - A monthly fixed price per kWh quoted by the Company, differentiated by on- and off-peak hours for the next calendar month. The quote will be made on the 15th of the preceding month (or the following working day if the 15th is a weekend or holiday) by a posting on the Company's website (www.PortlandGeneral.biz) and will be based on the expected market price for power delivered to the Company's service territory plus losses. The Customer will notify the Company by 5:00 p.m. PPT on the business day following such posting of its choice of this option.

Non-Cost of Service Options are subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

SCHEDULE 87 (Continued)

STANDARD BILL

The Standard Bill is calculated by applying the Annual Cost of Service Option under Schedule 89 to a CBL for each month of the year, excluding the Reactive Demand Charge and Adjustments identified in Schedule 100. If prices are revised, those changes will be reflected in the Customer's Standard Bill based on the CBL for a given month. Hourly Energy prices are applied only to kWh usage changes from the CBL in each hour.

CUSTOMER BASELINE LOAD (CBL)

The CBL is the Customer's hourly load for a 12-month period at typical levels of operation. It is developed based on the Customer's specific hourly load data or monthly billing data allocated to hours based on the consumption pattern agreed to by the Customer and the Company as typical of the Customer's operation.

Agreement to a CBL is a precondition for service under this schedule. The CBL is proprietary and will not be released to any other entity without the approval of the Customer and the Company. In order that the CBL reflect the Customer's Energy and Demand as accurately as possible, the Customer may request adjustments to the CBL for the following reasons:

1. The installation of permanent energy efficiency measures either as a participant in Energy Trust of Oregon programs or other verifiable conservation or technology improvement measures.
2. The addition or removal of equipment that results in a permanent change in the Customer's expected electricity consumption.

If the Customer leaves the program, he/she may not be allowed to return for a minimum of 12 months. A new CBL will be calculated in such cases based on the most recent usage. At a minimum, the CBL will be reviewed every three years and may be adjusted.

HOURLY ENERGY PRICE

Hourly Energy Prices are determined each day for the following day using Mid-Columbia Day Ahead Prices for on- and off-peak periods shaped to hourly prices based on the reported hourly Mid-Columbia prices from preceding days. The following charges will be added to the shaped hourly prices, 0.226¢ per kWh for wheeling, plus losses and the System Usage Charge as specified in Schedule 89. If prices are not reported for a particular day or days, the Company will estimate and shape prices from its hourly Energy price projections. (R)

In addition to the above charges, consumption of Energy above the CBL will be billed a 0.300¢ per kWh recovery factor. For consumption of Energy below the CBL, a 0.300¢ per kWh recovery factor will be subtracted from the Hourly Energy Price.

SCHEDULE 89
LARGE NONRESIDENTIAL (>1,000kW)
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$160.00	$230.00	$1,000.00	(I)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.75	$0.75	$0.75	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	
Over 1,000 kW	$0.61	$0.39	$0.39	(I)
per kW of monthly On-Peak Demand	$2.18	$2.18	$1.10	(R)
Energy Charge				
On-Peak Period***	6.865 ¢	6.618 ¢	6.519 ¢	(I)
Off-Peak Period***	5.367 ¢	5.171 ¢	5.090 ¢	(I)
See below for Daily or Monthly Pricing Option descriptions.				
System Usage Charge				
Per kWh	0.407 ¢	0.387 ¢	0.372 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.
*** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 89 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTIONS

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Quarterly Election Enrollment Window. **(R)**

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

Monthly Fixed Price Option - A monthly fixed price per kWh quoted by the Company, differentiated by on- and off-peak hours for the next calendar month. The quote will be made on the 15^{th} of the preceding month (or the following working day if the 15^{th} is a weekend or holiday) by a posting on the Company's website (www.PortlandGeneral.biz) and will be based on the expected market price for power delivered to the Company's service territory plus losses. The Customer will notify the Company by 5:00 p.m. PPT on the business day following such posting of its choice of this option.

Non-Cost of Service Options are subject to Schedule 128, Short Term Transition Adjustment

SCHEDULE 91 (Continued)

MAINTENANCE (Continued)

Maintenance of Option B luminaires includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance does not include replacement of a luminaire at end of life (when replacement of a part will not bring the unit into working condition and the unit is not inoperable due to damage from accident or vandalism). Option B Maintenance also does not include replacement of technologically obsolete luminaires still in working condition, or for which a simple part replacement (any combination of photocell, lamp, starter and refractor) will return obsolete lights to operable condition.

Non-Standard or Custom luminaires and poles are provided to allow greater flexibility in the choice of equipment. However, the Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. Also, this equipment is more subject to obsolescence. The Company will order and replace the equipment subject to availability.

If damage occurs to any lighting poles more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. Pole maintenance does not include painting of fiberglass, or painting or staining wood poles. It does not include testing or treating of wood poles. Maintenance of Option B poles does not include replacement of rotted wood poles that are no longer structurally sound, or any other poles which by definition have reached a natural end of life.

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each luminaire based on the Monthly kWhs applicable to each installed luminaire.

Transmission and Related Services Charge	0.127 ¢ per kWh	(I)
Distribution Charge	3.142 ¢ per kWh	
Energy Charge		
Cost of Service Option	5.857 ¢ per kWh	(I)

Daily Price Option – Available only to Customers with an average load of five MW or greater. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.226¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

SCHEDULE 91 (Continued)

MONTHLY RATE (Continued)

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily Energy Rate Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the above applicable Daily Price by 1.0834.

To begin service under this option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Cobrahead Power Doors **	100	9,500	43	*	$2.70	(R)
	150	16,000	62	*	2.71	
	200	22,000	79	*	2.76	
	250	29,000	102	*	2.73	
	400	50,000	163	*	2.74	
Cobrahead	100	9,500	43	$5.28	2.80	
	150	16,000	62	5.30	2.81	
	200	22,000	79	5.72	2.86	
	250	29,000	102	5.77	2.87	
	400	50,000	163	5.79	2.89	
Flood	250	29,000	102	6.04	2.90	
	400	50,000	163	6.06	2.92	(R)

* Not offered.
** Service is only available to Customers with total power door luminaries in excess of 2,500.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Early American Post-Top	100	9,500	43	$5.68	$2.80	(R)
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	5.90	2.88	
	100	9,500	43	6.11	2.90	
	150	16,000	62	6.38	2.93	(R)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black	20	$4.10	$0.14	
Fiberglass, Bronze	30	5.47	0.18	(I)
Fiberglass, Gray	30	5.49	0.18	(I)
Wood, Standard	30 to 35	4.71	0.15	
Wood, Standard	40 to 55	5.91	0.20	

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Acorn-Types						
HPS	100	9,500	43	$8.72	$3.21	(I)
HADCO Independence, HPS	100	9,500	43	8.01	3.09	
	150	16,000	62	8.02	3.10	
HADCO Capitol Acorn, HPS	100	9,500	43	12.29	3.58	
	150	16,000	62	12.31	3.60	
	200	22,000	79	12.31	3.60	
	250	29,000	102	12.31	3.60	
Special Architectural Types						
HADCO Victorian, HPS	150	16,000	62	8.44	3.19	
	200	22,000	79	8.49	3.20	
	250	29,000	102	8.58	3.21	(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
HADCO Techtra, HPS	100	9,500	43	$14.77	$3.85	(I)
	150	16,000	62	14.79	3.87	
	250	29,000	102	20.93	4.59	
KIM Archetype, HPS	250	29,000	102	*	3.34	
	400	50,000	163	*	3.34	(I)
HADCO Westbrooke, HPS	70	6,300	30	12.24	2.64	(R)
	100	9,500	43	12.19	2.62	
	150	16,000	62	12.20	2.63	
	200	22,000	79	12.34	2.63	
	250	29,000	102	12.36	2.65	(R)
Special Types						
Cobrahead, Metal Halide	175	12,000	71	5.50	2.95	(I)
Flood, Metal Halide	400	40,000	156	6.07	3.05	
Flood, HPS	750	105,000	285	8.41	4.00	
Holophane Mongoose, HPS	150	16,000	62	7.40	3.13	
	250	29,000	102	7.49	3.14	
	400	50,000	163	7.53	3.16	(I)

* Not offered.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$5.83	$0.20	(R)
	25	9.48	0.32	
	30	10.26	0.34	
	35	11.29	0.38	
Aluminum Davit	25	9.79	0.33	
	30	10.44	0.35	
	35	11.53	0.38	
	40	14.08	0.47	
Aluminum Double Davit	30	12.56	0.42	(R)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, HADCO, Fluted Victorian Ornamental	14	$11.08	$0.37	(R)
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	19.81	0.65	
Aluminum, HADCO, Fluted Ornamental	16	10.60	0.35	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	15.95	0.52	
Aluminum, Painted Ornamental	35	27.35	0.90	
Concrete, Ameron Post-Top	25	23.42	0.78	
Fiberglass, HADCO, Fluted Ornamental Black	14	6.47	0.21	
Fiberglass, Regular				
color may vary	22	3.17	0.11	
color may vary	35	7.47	0.25	
Fiberglass, Anchor Base, Gray	35	11.95	0.40	(R)
Fiberglass, Direct Bury with Shroud	18	6.20	0.21	

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$5.37	$2.70	(R)
	250	10,000	94	6.31	2.94	
	400	21,000	147	5.48	2.82	
	1,000	55,000	374	6.28	3.13	
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	8.68	2.80	
Mercury Vapor	175	7,000	66	8.90	2.80	(R)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Box, Anodized Aluminum Similar to GardCo Hub						
HPS	Twin 70	6,300	60	*	*	
	70	6,300	30	*	*	
	100	9,500	43	$8.52	$3.17	(I)(I)
	150	16,000	62	*	3.18	(I)
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	3.35	(I)
	400	40,000	156	*	3.76	(I)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	2.80	(R)
100/150 Watt Ballast	100	9,500	43	*	2.80	
100/150 Watt Ballast	150	16,000	62	*	2.81	(R)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	3.62	(I)
Special Acorn-Type, HPS	70	6,300	30	8.45	2.80	(R)(R)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	
Special Acrylic Sphere						
Mercury Vapor	400	21,000	147	*	*	
Early American Post-Top, HPS						
Black	70	6,300	30	5.17	2.81	(R)(R)
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.50	2.72	(R)(R)

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Flood, HPS	70	6,300	30	$5.75	$2.86	(R)
	100	9,500	43	5.65	2.84	
	200	22,000	79	6.04	2.90	
Cobrahead, HPS						
Non-Power Door	70	6,300	30	5.19	2.80	
Power Door	310	37,000	124	6.47	3.21	(R)
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Flourescent	28	N/A	12	*	*	

* Not offered.

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B	
Aluminum Post	30	$5.83	*	
Bronze Alloy GardCo	12	*	$0.24	
Concrete, Ornamental	35 or less	9.48	0.32	(R)
Steel, Painted Regular **	25	9.48	0.32	
Steel, Painted Regular **	30	10.26	0.34	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.34	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.35	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.38	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.38	(R)
Wood, Laminated without Mast Arm	20	5.30	0.14	
Wood, Laminated Street Light Only	20	4.10	*	

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES (Continued)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Wood, Curved Laminated	30	$6.84	$0.25	(R)
Wood, Painted Underground	35	4.71	0.20	
Wood, Painted Street Light Only	35	4.71	*	

* Not offered.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	$10.62	$2.08	(R)
	165	12,000	60	12.32	2.17	(I)
HADCO Techtra, QL	85	6,000	32	13.99	2.20	(R)
	165	12,000	60	14.72	2.26	(R)

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

During the Quarterly Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

SCHEDULE 92
TRAFFIC SIGNALS
(NO NEW SERVICE)
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments where funds for payment of Electricity are provided through taxation or property assessment for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Transmission and Related Services Charge	0.144	¢ per kWh	(I)
Distribution Charge	2.162	¢ per kWh	
Energy Charge	6.191	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Quarterly Election Window

The Quarterly Election Window begins at 8:00 a.m. on February 15th, May 15th and August 15th (or the following business day if the 15th falls on a weekend or holiday). The Quarterly Election Windows will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

During the Quarterly Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st; for the May 15th election window, the election is effective July 1st and for the August 15th election window, the election is effective on October 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Quarterly Election Window.

SCHEDULE 93
RECREATIONAL FIELD LIGHTING, PRIMARY VOLTAGE
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for recreational field lighting and related incidental lighting.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$30.00		
Transmission and Related Services Charge	0.180	¢ per kWh	(R)
Distribution Charge	9.266	¢ per kWh	(I)
Energy Charge	6.300	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge, if necessary, to justify the Company's investment in service facilities.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITION

The Customer's electrical equipment and its installation must be approved by the Company. All service under this schedule at any one location will be supplied through one meter.

TERM

Service under this schedule will not be for less than a one year.

SCHEDULE 94
COMMUNICATION DEVICES ELECTRICITY SERVICE RIDER

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments that have communication devices with energy requirements not exceeding 25 line watts per unit, that are installed on streetlights and, or traffic signals served under Schedules 91 and, or 92.

CHARACTER OF SERVICE

60-hertz alternating current of such phase and voltage as the Company may have available.

SERVICE

Service under this schedule will be based on an estimated total monthly kWh used, as determined by the Company, for all the Customer's devices. The estimated monthly usage will be updated as needed to reflect device installations or removals. Monthly kilowatt-hour usage will be computed on the basis of manufacturer's line wattage ratings of installed devices, with no allowances for outages.

MONTHLY RATE

The sum of the following charges per Point of Delivery:*

Transmission and Related Services Charge	0.144 ¢ per kWh	(I)
Distribution Charge	2.162 ¢ per kWh	(I)
Energy Charge	6.191 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments

The monthly kWh charge for service under this rider will be the number of units times estimated monthly usage determined using the following formula:

[((No. of Units x line watts per unit) x annual operating hours) / 1000] / 12

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules.

APPLICABLE ADJUSTMENT SCHEDULES

(N)

Schedules	102	105	106	107	108	115	120	122	123	125	126	128	129	130
	(1)		(1)		(3)		(1)			(1)		(4)	(1)	(1)
7	x	x	x	x	x	x	x	x	x	x	x			
9			x(1)		x	x								
15	x	x	x	x	x	x	x	x	x	x	x			
32	x	x	x	x	x	x	x	x	x	x	x	x		
38	x	x	x	x	x	x	x	x	x	x	x	x		x
47	x	x	x	x	x	x	x	x	x	x	x			
49	x	x	x	x	x	x	x	x	x	x	x			
75	x(2)	x(2)	x	x(2)	x	x	x(2)	x(2)	x	x(2)	x(2)	x		
76R	x	x	x	x	x	x			x					
83	x	x	x	x	x	x	x	x	x	x	x	x		x
87	x(2)	x(2)	x	x(2)	x	x	x(2)	x(2)	x	x	x(2)			
89	x	x	x	x	x	x	x	x	x	x	x	x		x
91		x	x	x	x	x	x	x	x	x	x	x		
92		x	x	x	x	x	x	x	x	x	x			
93		x	x	x	x	x	x	x	x	x	x			
94		x	x	x	x	x	x	x	x	x	x			
483	x	x	x	x	x	x			x		x(5)		x	
489	x	x	x	x	x	x			x		x(5)		x	
515	x	x	x	x	x	x		x	x		x(5)	x		
532	x	x	x	x	x	x		x	x		x(5)	x		
538	x	x	x	x	x	x		x	x		x(5)	x		x
549	x	x	x	x	x	x		x	x		x(5)	x		
575	x(2)	x(2)	x	x(2)	x	x		x(2)	x		x(2)	x		
576R	x	x	x	x	x	x			x					
583	x	x	x	x	x	x		x	x		x(5)	x		x
589	x	x	x	x	x	x		x	x		x(5)	x		x
591		x	x	x	x	x		x	x		x(5)	x		
592		x	x	x	x	x		x	x		x(5)	x		
594		x	x	x	x	x		x	x		x	x		

(N)

(1) Where applicable.
(2) These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Schedule 108 applies to the sum of all charges less taxes, Schedule 115 charges and one-time charges such as deposits.
(4) Applicable to Nonresidential Customer who receive service at Daily or Monthly pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 483 and 489).
(5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 120
BIGLOW CANYON I ADJUSTMENT

PURPOSE

This schedule recovers the net costs of the Company's Biglow Canyon I wind project. Approval of this tariff adjustment will be considered a Commission revision of the Company's ratio of net revenues to gross revenues and effective tax rate for purposes of OAR 860-22-0041.

AVAILABLE

In all territory served by the Company

APPLICABLE

To all bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 87, 89, 91, 92, 93 and 94.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after January 1, 2009, are: (C)

Schedule	Adjustment Rate	
7	0.000 ¢ per kWh	(R)
15	0.000 ¢ per kWh	
32	0.000 ¢ per kWh	
38	0.000 ¢ per kWh	
47	0.000 ¢ per kWh	
49	0.000 ¢ per kWh	
75		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
83		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
87		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	
89		
Secondary	0.000 ¢ per kWh	
Primary	0.000 ¢ per kWh	
Subtransmission	0.000 ¢ per kWh	(R)

SCHEDULE 120 (Concluded)

ADJUSTMENT RATE (Continued)

Schedule	Adjustment Rate	
91	0.000 ¢ per kWh	(R)
92	0.000 ¢ per kWh	|
93	0.000 ¢ per kWh	(R)
94	0.000 ¢ per kWh	

SPECIAL CONDITIONS

1. Rates under this schedule will recover the net costs of Biglow Canyon I from all applicable customers on an equal cents per kWh basis adjusted for delivery voltage.

2. The rates contained in this schedule will, if necessary, be revised and refiled on November 15, 2007 to be consistent with the load forecast and forward price curves used in the Annual Power Cost Update also filed on that date. The rates in this schedule will be added to the applicable rate schedules' Cost of Service Energy Charges for purposes of calculating the Schedule 128, Short-Term Transition Adjustment.

3. If the Biglow Canyon I wind project is not expected to achieve commercial operation by January 1, 2008, the Company will notify the Commission by December 31, 2007. In such case, the effective date of the above adjustment rates will be delayed until one day after the Company notifies the Commission that the project has achieved commercial operation.

4. Any power produced by Biglow Canyon 1 prior to January 1, 2008 will be valued for power cost purposes at the monthly average of the daily Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) for determining actual NVPC under Schedule 126, Annual Power Cost Variance Mechanism.

5. The Biglow Canyon 1 revenue requirements recovered under this schedule that are not otherwise recovered through Schedule 125 will be updated annually and will continue to be recovered under this Schedule 120 until such costs are included in base rates. Beginning in 2008, if the Company has not filed a general rate case by April 1 of any year, the Company will file by April 1 proposed updates to this schedule and the revenue requirement update process will be on the same schedule as updates to Schedule 125. The annual update will include updates to gross revenues, net revenues, and total income tax expense for the calculation of "taxes authorized to be collected in rates" pursuant to OAR 860-022-0041.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 123
SALES NORMALIZATION ADJUSTMENT

PURPOSE

This Schedule establishes a balancing account and rate adjustment mechanism to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Point of Delivery during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

> **Energy Efficiency Measures (EEMs)** – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.
>
> **Self-Directing Customer (SDC)** - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, for Customers served under Schedules 7, 32 and 532, differences between a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) of 5.082 cents/kWh for Schedule 7 and 4.625 cents/kWh for Schedules 32 and 532 to weather-normalized kWh Energy sales, and 2) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer of $45.59 per month for Schedule 7 and $69.10 per month for Schedules 32 and 532 to the number of active Schedule 7 and Schedule 32 and 532 Customers respectively for each month.

The SNA will calculate monthly as the Fixed Charge Revenue less actual weather-adjusted revenues and will accrue to the SNA Balancing Account. Such monthly amount which may be positive (an undercollection) or negative (an overcollection) will accrue to the Sales Normalization Balancing Account.

SCHEDULE 123 (Continued)

NONRESIDENTIAL LOST REVENUE RECOVERY

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532 or otherwise as exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during the prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates.

Lost Revenue Recovery may be positive or negative. Negative Lost Revenue Recovery will occur if actual kWh savings are less than estimated in setting base rates.

For the purposes of this Schedule, Lost Revenue Recovery is the product of the reduction in kWh sales resulting from ETO-reported EEMs and the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule weighted average of transmission, distribution, and fixed generation charges including those contained in Schedules 120 and 122. Schedules 32 and 532 are not included in the weighted average base rate calculation. System usage charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. As of the effective date of this schedule, the applicable Lost Revenue Rate is 3.520 ¢ per kWh.

SALES NORMALIZATION ADJUSTMENT AND LOST REVENUE BALANCING ACCOUNT

The Company will maintain a separate balancing account for the SNA, applicable to Schedules 7, 32 and 532 and for the Nonresidential Lost Revenue Recovery for the remaining applicable nonresidential Schedules. The balancing accounts will record over- and under-collections resulting from differences as determined by the SNA and Lost Revenue Recovery mechanisms. The accounts will accrue interest at the Company's authorized rate of return.

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA)

The Adjustment Rates, applicable for service on and after the effective date of this schedule will be:

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
15	0.000 ¢ per kWh
32	0.000 ¢ per kWh
38	0.000 ¢ per kWh
47	0.000 ¢ per kWh
49	0.000 ¢ per kWh
75	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
76R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
83	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
87	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
89	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
91	0.000 ¢ per kWh
92	0.000 ¢ per kWh
93	0.000 ¢ per kWh
94	0.000 ¢ per kWh

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

Schedule	Adjustment Rate
483	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
489	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
515	0.000 ¢ per kWh
532	0.000 ¢ per kWh
538	0.000 ¢ per kWh
549	0.000 ¢ per kWh
575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
576R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
583	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
589	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
591	0.000 ¢ per kWh
592	0.000 ¢ per kWh
594	0.000 ¢ per kWh

SCHEDULE 123 (Concluded)

TIME AND MANNER OF FILING

Commencing in 2010, the Company will submit to the Commission the following information by April 1 of each year:

1. The proposed price changes to this Schedule to be effective on June 1st of the submittal year based on a) the amount in the SNA Balancing Account at the end of the previous calendar year, and b) the amount in the Lost Revenue Recovery Balancing Account amount at the end of the previous calendar year.

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers.

3. The status of the SNA and Lost Revenue Balancing Accounts.

SPECIAL CONDITIONS

1. The Fixed Charge Energy Rate, Monthly Fixed Charge per Customer Rate and the Lost Revenue Rate will be updated concurrently with a change in the applicable base revenues used to determine the charge.

2. Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that determination of forecasted loads used to set rates.

3. No revision to the Sales Normalization Adjustment Rates will result in an estimated average annual rate increase greater than 2% to the applicable SNA rate schedules or to the applicable Lost Revenue Recovery rate schedules based on the net rates in effect on the effective date of the rate revision under this schedule. Any remaining amounts in the Balancing Accounts will be included in subsequent revisions to the Sales Normalization Rates. Rate revisions resulting in a rate decrease are not subject to the 2% limit.

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs. This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 87, 89, 91, 92, 93 and 94.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs. (C)
- No other changes or updates will be made in the annual filings under this schedule.

ADJUSTED NET VARIABLE POWER COSTS (T)

Adjusted Net Variable Power Costs for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update plus changes in fixed generation revenues caused by the change in Cost of Service loads resulting from either return to or departures from Cost of Service pricing by Schedule 483 and 489 customers relative to the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0342. (C) (C)(I)

SCHEDULE 125 (Continued)

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final unit change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine the Annual Power Cost Update. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices. (C)

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh	
7		0.000	(I)
15		0.000	
32		0.000	
38	Large Nonresidential	0.000	
47		0.000	
49		0.000	
75	Secondary	0.000 (1)	
	Primary	0.000 (1)	
	Subtransmission	0.000 (1)	
83	Secondary	0.000	
	Primary	0.000	
87	Secondary	0.000	
	Primary	0.000	
	Subtransmission	0.000	(I)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh	
89	Secondary	0.000	(I)
	Primary	0.000	
	Subtransmission	0.000	
91		0.000	
92		0.000	
93		0.000	
94		0.000	(I)

SPECIAL CONDITIONS (N)

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

2. In determining changes in fixed generation revenues from movement to or from Schedules 483 and 489, the following factors will be used:

Schedule		¢ per kWh	
83	Secondary	1.942	
	Primary	1.879	
89	Secondary	1.950	
	Primary	1.860	
	Subtransmission	1.818	(N)

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those served on Schedule 76R and 576R, and those served on Schedules 483, 489, 515, 532, 538, 549, 583, 589, 591, 592 and 594, where service under these schedules was received for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 589, 591 and 592 who receive the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE (PVC)

Subject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual Variance amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. Interest will accrue on the account at the Company's authorized rate of return. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest on the PCV Account calculated at the Company's authorized cost of capital. This amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0342 (I)
to account for franchise fees, uncollectibles, and OPUC fees. (T)

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount to the extent that such refunding will not cause the Company's Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

Schedule 126 (Continued)

DEFINITIONS (Continued)

Net Variable Power Costs (NVPC)

The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission / wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 38, 83, 89, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 483 and 489 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0342 to account for franchise fees, uncollectables, and (T)(I)
OPUC fees. (T)

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily or Monthly pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 89 or 91; or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 589, 591, 592, 594. This Schedule is not applicable to Customers served on Schedules 483 and 489.

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service for 2008, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2008:

Schedule		Annual ¢ per kWh [(1)]	
32		(0.891)	(I)
38		(0.889)	
75	Secondary On-Peak	(0.962) [(2)]	
	Secondary Off-Peak	(0.753) [(2)]	
	Primary On-Peak	(0.928) [(2)]	
	Primary Off-Peak	(0.726) [(2)]	
	Subtransmission On-Peak	(0.914) [(2)]	
	Subtransmission Off-Peak	(0.714) [(2)]	
83	Secondary	(0.885)	
	Primary	(0.857)	(I)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh [(1)]	
89	Secondary On-Peak	(0.962)	(I)
	Secondary Off-Peak	(0.753)	
	Primary On-Peak	(0.928)	
	Primary Off-Peak	(0.726)	
	Subtransmission On-Peak	(0.914)	
	Subtransmission Off-Peak	(0.714)	
91		(0.822)	
515		(0.822)	
532		(0.891)	
538		(0.889)	
549		(0.858)	
575	Secondary On-Peak	(0.962) [(2)]	
	Secondary Off-Peak	(0.753) [(2)]	
	Primary On-Peak	(0.928) [(2)]	
	Primary Off-Peak	(0.726) [(2)]	
	Subtransmission On-Peak	(0.914) [(2)]	
	Subtransmission Off-Peak	(0.714) [(2)]	
583	Secondary	(0.885)	
	Primary	(0.857)	
589	Secondary On-Peak	(0.962)	
	Secondary Off-Peak	(0.753)	
	Primary On-Peak	(0.928)	
	Primary Off-Peak	(0.726)	
	Subtransmission On-Peak	(0.914)	
	Subtransmission Off-Peak	(0.714)	
591		(0.822)	
592		(0.868)	
594		(0.868)	(I)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term Transition Adjustment rate will be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. Indicative, non-binding estimates for the Annual Short-Term Transition Adjustment will be posted by the Company two months and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

SCHEDULE 128 (Continued)

LARGE NONRESIDENTIAL LOAD SHIFT TRUE-UP

For the November window, the Company will compute the Load Shift True-Up as the difference between the market prices used to establish the Schedule 128 Transition Adjustment and the average of the corresponding projected market prices during the first full week in December times the load leaving Cost of Service pricing. For the Balance of Year Transition Adjustment windows, the Company will compute the True-Up as the difference between the market prices used to establish the Schedule 128 Transition Adjustments and the corresponding projected market prices during the first full week after the close of the window times the amount of load leaving Cost of Service pricing. For the November election window, the Company will file for a deferral after the close of the window if the True-Up is greater than $240,000. The filing threshold for each of the quarterly windows will be $60,000. (C)

BALANCING ACCOUNT

The Company will maintain a Balancing Account to accrue any deferred load shift true-up amounts. The Balancing Account will accrue interest at the Company's authorized cost of capital. These monies will be recovered from or refunded to all direct-access eligible Large Nonresidential Customers in a manner approved by the Commission.

CHANGES TO TRANSITION ADJUSTMENT RATES

The Short-Term Transition Adjustment is subject to modification to reflect any changes to the Energy Charge(s) of the Cost of Service Option that serve as the basis for the calculation of the Transition Adjustment. No change will be made, however, to the market price of power used to determine the applicable adjustment rate.

BALANCE-OF-YEAR TRANSITION ADJUSTMENT RATE

Eligible customers who have elected to receive service on a rate other than Cost of Service during a Quarterly Enrollment Window, will have the applicable Short-Term Balance-of-Year Transition Adjustment Rate applied to their bills.

The Balance-of-Year Transition Adjustment Rate will be filed, posted on the Company's website and incorporated into this Schedule effective as follows:

- February 15th for an April 1st effective date
- May 15th for a July 1st effective date
- August 15th for an October 1st effective date

Where the date above is a weekend or state-recognized holiday, the filing date will be the next business day. The Short-Term Balance-of-Year Transition Adjustment will be posted by the Company on its website (www.PortlandGeneral.biz) on the day the rate is filed with the Commission.

SCHEDULE 129 (Concluded)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out

For Enrollment Period F (2007), the Transition Cost Adjustment will be:

(1.250) ¢ per kWh	January 1, 2008 through December 31, 2008
(1.434) ¢ per kWh	January 1, 2009 through December 31, 2009
(1.248) ¢ per kWh	January 1, 2010 through December 31, 2010

SPECIAL CONDITION

Annually, the total amount paid in Schedule 129 Long-Term Transition Cost Adjustment will be collected through applicable Large Nonresidential rate schedules (Schedules 75, 76R, 83, 89, 483, (C)
489, 575, 576R, 583, 589), through either the System Usage or Distribution Charges. Such (C)
adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedule 483 or 489.

SCHEDULE 300
CHARGES AS DEFINED BY THE RULES AND REGULATIONS AND MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to list the charges referred to in the General Rules and Regulations.

AVAILABLE

In all territory served by the Company.

APPLICABLE

For all Customers utilizing the services of the Company as defined and described in the General Rules and Regulations.

INTEREST ACCRUED ON DEPOSITS (See Rules D and H)

4% per annum.

BILLING RATES (Rules C, E, F, H, I and J)
Trouble call, cause in Customer-owned equipment

Scheduled Crew Hours [(1)]	No charge	
Other than Scheduled Crew Hours [(1)]	$170.00	
Returned Payment Charge	$ 25.00	
Special Meter Reading Charge	$ 35.00	
Meter Test Charge	$ 75.00	
Late Payment Charge	1.7% of delinquent balance	
Field Visit Charge [(2)]	$ 45.00	(I)
Bill History Information Service Charge (Not applicable when a billing dispute is filed with the Commission - see Rule F)	$ 32.00	
Portfolio Enrollment Charge	$ 5.00	
Customer Interval Data (12 months) to Customers	$100.00	
Customer Interval Data (12 months, formatted and analyzed)	Mutually agreed price	
Switching Fee	$20.00	
Unauthorized Connection of Service / Tamper Fee	$75.00	

(1) Scheduled Crew Hours - The Company's Scheduled Crew Hours for the above listed services are from 6:30 a.m. to 10:30 p.m., Monday through Friday, except for Company-recognized holidays. The Customer will be informed of and agree to the charges before Company personnel are dispatched.
(2) See Rule H, Section 2 for applicable conditions.

SCHEDULE 300 (Continued)

CREDIT RELATED DISCONNECTION AND RECONNECTION RATES (Rule H)

Disconnects		
Monday through Friday	No charge	
Reconnection		
Standard Reconnection		
At Meter Base	$ 45.00	(I)
Other than Meter Base	$ 210.00	(I)
After Hours Reconnection[1]		
At Meter Base	$ 80.00	
Other than Meter Base	$ 575.00	(I)

CUSTOMER REQUESTED DISCONNECTION AND RECONNECTION RATES (Rule H)[2][3]

Disconnects		
Standard		
At Meter Base	No charge	
Other than Meter Base	No charge	
After Hours		
Non-safety related		
At Meter Base	$ 325.00	(I)
Other than Meter Base	$ 575.00	(I)
Reconnects		
Standard		
Safety related	No charge	
Non-safety related		
At Meter Base	$ 45.00	(I)
Other than Meter Base	$ 210.00	(I)
After Hours		
At Meter Base	$ 325.00	(I)
Other than Meter Base	$ 575.00	(I)

(1) PGE representatives will be dispatched to reconnect service until 7:00 p.m., Monday through Friday. As such, crews dispatch up to and including 7:00 p.m. may be reconnecting service after 7:00 p.m. State- and utility-recognized holidays are excluded from the after hours provision.

(2) These rates apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In other cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.

(3) No charge for disconnects / reconnects completed to ensure safe working conditions that meet the guidelines in Rule H(4).

SCHEDULE 483 (Continued)

ENROLLMENT PERIODS (Continued)

Fixed Three-Year Option (Continued)

Enrollment Period C: Applicable to any Customer who enrolled between September 1 and September 30, 2004, with a service period from January 1, 2005 through December 31, 2007.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

Enrollment Period F: Applicable to any Customer who enrolled between September 1, 2007 and September 30, 2007, with a service period from January 1, 2008 through December 31, 2010.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

MONTHLY RATE

The monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge			
Single Phase Service	$20.00		(T)
Three Phase Service	$25.00	$80.00	(T)(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 30 kW	$1.54	$1.81	(R)
Over 30 kW	$2.34	$1.81	(I)(N)
per kW of monthly Demand	$2.13	$2.13	(I)(R) (D)
System Usage Charge			
per kWh	0.419 ¢	0.403 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

Advice No. 08-02
Issued February 27, 2008
James J. Piro, Executive Vice President

Effective for service
on and after April 1, 2008

SCHEDULE 483 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.529 per kW of monthly Demand. (R)

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

SCHEDULE 489 (Continued)

ENROLLMENT PERIODS (Continued)

Fixed Three-Year Option (Continued)

Enrollment Period C: Applicable to any Customer who enrolled between September 1 and September 30, 2004, with a service period from January 1, 2005 through December 31, 2007.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

Enrollment Period F: Applicable to any Customer who enrolled between September 1, 2007 and September 30, 2007, with a service period from January 1, 2008 through December 31, 2010.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$160.00	$230.00	$1,000.00	**(I)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	**(I)**
Over 1,000 kW	$0.61	$0.39	$0.39	**(I)**
per kW of monthly On-Peak Demand	$2.18	$2.18	$1.10	**(R)**
System Usage Charge				
per kWh	0.407 ¢	0.387 ¢	0.372 ¢	**(R)(I)**

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

Wheeling Charge

The Wheeling Charge will be $1.529 per kW of monthly Demand. (R)

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

SCHEDULE 515
OUTDOOR AREA LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Nonresidential Customers purchasing Direct Access Service for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer or Electricity Service Supplier (ESS) notifies the Company of the burn-out.

MONTHLY RATE

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Cobrahead					
Mercury Vapor	175	7,000	66	$7.74 [2]	(R)
	400	21,000	147	10.38 [2]	
	1,000	55,000	374	18.33 [2]	
HPS	70	6,300	30	6.41 [2]	
	100	9,500	43	6.90	
	150	16,000	62	7.53	
	200	22,000	79	8.52	
	250	29,000	102	9.29	
	310	37,000	124	10.71 [2]	
	400	50,000	163	11.22	(R)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire	
Flood , HPS	100	9,500	43	$7.31 [2]	(R)
	200	22,000	79	8.61 [2]	
	250	29,000	102	9.60	
	400	50,000	163	11.52	(R)
Shoebox, HPS (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	7.27	(N)
	100	9,500	43	7.82	(R)
	150	16,500	62	8.72	(R)
Special Acorn Type, HPS	100	9,500	43	10.70	(I)
HADCO Victorian, HPS	150	16,500	62	10.99	
	200	22,000	79	11.57	(I)
	250	29,000	102	12.39	(R)
Early American Post-Top, HPS, Black	100	9,500	43	7.78	
Special Types					
Cobrahead, Metal Halide	175	12,000	71	8.02	
Flood, Metal Halide	400	40,000	156	11.29	
Flood, HPS	750	105,000	285	17.82	
HADCO Independence, HPS	100	9,500	43	9.92	
	150	16,000	62	10.53	(R)
HADCO Capitol Acorn, HPS	100	9,500	43	14.63	(I)
	150	16,000	62	15.25	
	200	22,000	79	15.78	
	250	29,000	102	16.50	
HADCO Techtra, HPS	100	9,500	43	17.38	
	150	16,000	62	18.00	
	250	29,000	102	26.01	(I)
KIM Archetype, HPS	250	29,000	102	13.85	
	400	50,000	163	15.57	(R)
Holophane Mongoose, HPS	150	16,000	62	9.84	
	250	29,000	102	11.18	
	400	40,000	163	13.12	(R)

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Wood, Standard	35 or less	$5.98	
	55 or less	7.51	
Wood, Painted Underground	35 or less	6.99 [2]	
Wood, Curved laminated	30 or less	8.68 [2]	(I)
Aluminum, Regular	16	7.40	
	25	12.03	(I)
	30	13.03	
	35	14.33	
Aluminum, Fluted Ornamental	14	14.07	
Aluminum Davit	25	12.43	
	30	13.25	
	35	14.65	
	40	17.88	
Aluminum Double Davit	30	15.95	
Aluminum, HADCO, Fluted Ornamental	16	13.47	
Aluminum, HADCO, Non-fluted	18	25.16	
Concrete, Ameron Post-Top	25	29.74	
Fiberglass Fluted Ornamental; Black	14	8.22	(I)
Fiberglass, Regular			
Black,	20	5.20	
Gray or Bronze;	30	6.97	(I)
Other Colors (as available)	35	9.48	
Fiberglass, Anchor Base Gray	35	15.17	(I)
Fiberglass, Direct Bury with Shroud	18	7.87	

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Single Phase	$14.35	
Three Phase	$20.25	
Distribution Charge		
First 5,000 kWh	2.987 ¢ per kWh	(I)
Over 5,000 kWh	0.576 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00		
Distribution Charge	3.875	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges per Point of Delivery (POD)*:

Basic Charge		
Summer Months**	$30.00	
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	3.276 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	1.276 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply all or some portion of their load by self generation operating on a regular basis, where the self-generation has a total nameplate rating of 1 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge				
Three Phase Service	$160.00	$230.00	$1,000.00	(I)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	(I)
Over 1,000 kW	$0.61	$0.39	$0.39	(I)
per kW of monthly On-Peak Demand**	$2.18	$2.18	$1.10	(R)
Generation Contingency Reserves Charges***				
Spinning Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.407 ¢	0.387 ¢	0.372 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.
*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Delivery Voltage		
	Secondary and Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge			
per kW of Daily ERP Demand during On-Peak hours per day**	$0.085	$0.043	(R)
System Usage Charge			
per kWh of ERP		0.372 ¢	(I)
Transaction Fee			
per Energy Needs Forecast (ENF) submission or revision		$50.00	

* See Schedule 100 for applicable adjustments.
** Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has not exceeded 1,000 kW more than once in the proceeding 13 months and who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	
Basic Charge			
Single Phase Service	$20.00		
Three Phase Service	$25.00	$80.00	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 30 kW	$1.54	$1.81	(R)
Over 30 kW	$2.34	$1.81	(I)(N)
per kW of monthly Demand	$2.13	$2.13	(I)(R) (D)
System Usage Charge			
per kWh	0.419 ¢	0.403 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 589
LARGE NONRESIDENTIAL
(>1000 kW)
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 kW, and who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$160.00	$230.00	$1,000.00	(I)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 1,000 kW	$2.05	$1.83	$1.83	(I)
Over 1,000 kW	$0.61	$0.39	$0.39	(I)
per kW of monthly on-peak Demand	$2.18	$2.18	$1.10	(R)
System Usage Charge				
per kWh	0.407 ¢	0.387 ¢	0.372 ¢	(R)(I)

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 591 (Continued)

MAINTENANCE (Continued)

Maintenance of Option B luminaires includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance does not include replacement of a luminaire at end of life (when replacement of a part will not bring the unit into working condition and the unit is not inoperable due to damage from accident or vandalism). Option B Maintenance also does not include replacement of technologically obsolete luminaires still in working condition, or for which a simple part replacement (any combination of photocell, lamp, starter and refractor) will return obsolete lights to operable condition.

Non-Standard or Custom luminaires and poles are provided to allow greater flexibility in the choice of equipment. However, the Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. Also, this equipment is more subject to obsolescence. The Company will order and replace the equipment subject to availability.

If damage occurs to any lighting poles more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. Pole maintenance does not include painting of fiberglass, or painting or staining wood poles. It does not include testing or treating of wood poles. Maintenance of Option B poles does not include replacement of rotted wood poles that are no longer structurally sound, or any other poles which by definition have reached a natural end of life.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each luminaire based on the Monthly kWhs applicable to each installed luminaire.

Distribution Charge	3.142 ¢ per kWh	(I)
Energy Charge	Provided by Energy Service Supplier	

SCHEDULE 591 (Continued)

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead Power Doors **	100	9,500	43	*	$4.05	$1.35	(R)(I)
	150	16,000	62	*	4.66	1.95	
	200	22,000	79	*	5.24	2.48	
	250	29,000	102	*	5.93	3.20	
	400	50,000	163	*	7.86	5.12	
Cobrahead	100	9,500	43	$6.63	4.15	1.35	
	150	16,000	62	7.25	4.76	1.95	
	200	22,000	79	8.20	5.34	2.48	
	250	29,000	102	8.97	6.07	3.20	(R)
	400	50,000	163	10.91	8.01	5.12	
Flood	250	29,000	102	9.24	6.10	3.20	
	400	50,000	163	11.18	8.04	5.12	
Early American Post-Top	100	9,500	43	7.03	4.15	1.35	(R)
Shoebox (Bronze color, flat	70	6,300	30	6.84	3.82	0.94	
Lens, or drop lens, multi-volt)	100	9,500	43	7.46	4.25	1.35	(R)
	150	16,000	62	8.33	4.88	1.95	(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black	20	$4.10	$0.14	
Fiberglass, Bronze	30	5.47	0.18	(R)
Fiberglass, Gray	30	5.49	0.18	(R)
Wood, Standard	30 to 35	4.71	0.15	
Wood, Standard	40 to 55	5.91	0.20	

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Types							
HPS	100	9,500	43	$10.07	$4.56	$1.35	(I)
HADCO Independence, HPS	100	9,500	43	9.36	4.44	1.35	
	150	16,000	62	9.97	5.05	1.95	
HADCO Capitol Acorn, HPS	100	9,500	43	13.64	4.93	1.35	
	150	16,000	62	14.26	5.55	1.95	
	200	22,000	79	14.79	6.08	2.48	
	250	29,000	102	15.51	6.80	3.20	
Special Architectural Types							
HADCO Victorian, HPS	150	16,000	62	10.39	5.14	1.95	
	200	22,000	79	10.97	5.68	2.48	
	250	29,000	102	11.78	6.41	3.20	
HADCO Techtra, HPS	100	9,500	43	16.12	5.20	1.35	
	150	16,000	62	16.74	5.82	1.95	
	250	29,000	102	24.13	7.79	3.20	
KIM Archetype, HPS	250	29,000	102	*	6.54	3.20	
	400	50,000	163	*	8.46	5.12	
HADCO Westbrooke, HPS	70	6,300	30	13.18	3.58	0.94	(R)
	100	9,500	43	12.16	2.59	1.35	
	150	16,000	62	12.77	3.20	1.95	
	200	22,000	79	13.44	3.73	2.48	
	250	29,000	102	14.18	4.47	3.20	(R)
Special Types							
Cobrahead, Metal Halide	175	12,000	71	7.73	5.18	2.23	
Flood, Metal Halide	400	40,000	156	10.97	7.95	4.90	
Flood, HPS	750	105,000	285	17.36	12.95	8.95	
Holophane Mongoose, HPS	150	16,000	62	9.35	5.08	1.95	
	250	29,000	102	10.69	6.34	3.20	
	400	50,000	163	12.65	8.28	5.12	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, Regular	16	$5.83	$0.20	
	25	9.48	0.32	(R)
	30	10.26	0.34	
	35	11.25	0.38	
Aluminum Davit	25	9.79	0.33	
	30	10.44	0.35	
	35	11.53	0.38	
	40	14.08	0.47	
Aluminum Double Davit	30	12.56	0.42	
Aluminum, HADCO, Fluted Victorian Ornamental	14	11.08	0.37	
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	19.81	0.65	
Aluminum, HADCO, Fluted Ornamental	16	10.60	0.35	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	15.95	0.52	
Aluminum, Painted Ornamental	35	27.35	0.90	
Concrete, Ameron Post-Top	25	23.42	0.78	
Fiberglass, HADCO, Fluted Ornamental Black	14	6.47	0.21	(R)
Fiberglass, Regular,				
color may vary	22	3.17	0.11	
color may vary	35	7.47	0.25	(R)
Fiberglass, Anchor Base, Gray	35	11.95	0.40	(R)
Fiberglass, Direct Bury with Shroud	18	6.20	0.21	

Advice No. 08-02
Issued February 27, 2008
James J. Piro, Executive Vice President

Effective for service
on and after April 1, 2008

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$1.23	(I)
	175	7,000	66	$7.44	$4.77	2.07	(R)
	250	10,000	94	9.26	5.89	2.95	
	400	21,000	147	10.10	7.44	4.62	
	1,000	55,000	374	18.03	14.88	11.75	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	9.62	3.74	0.94	(R)
Mercury Vapor	175	7,000	66	10.97	4.87	2.07	(R)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	1.89	
	70	6,300	30	*	*	0.94	
	100	9,500	43	9.87	4.52	1.35	
	150	16,000	62	*	5.13	1.95	
	250	29,000	102	*	*	3.20	
	400	50,000	163	*	*	5.12	
Metal Halide	250	20,500	99	*	6.46	3.11	
	400	40,000	156	*	8.66	4.90	
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	4.15	1.35	(R)
100/150 Watt Ballast	100	9,500	43	*	4.15	1.35	
100/150 Watt Ballast	150	16,000	62	*	4.76	1.95	(R)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.57	1.95	(I)

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Acorn-Type, HPS	70	6,300	30	$9.39	$3.74	$0.94	(R)(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	0.94	
Mercury Vapor	175	7,000	66	*	*	2.07	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	4.62	
Early American Post-Top, HPS							
Black	70	6,300	30	6.11	3.75	0.94	
Rectangle Type	200	22,000	79	*	*	2.48	
Incandescent	92	1,000	31	*	*	0.97	
	182	2,500	62	*	*	1.95	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	7.57	4.79	2.07	
Flood, HPS	70	6,300	30	6.69	3.80	0.94	
	100	9,500	43	7.00	4.19	1.35	
	200	22,000	79	8.52	5.38	2.48	
Cobrahead, HPS							
Non-Power Door	70	6,300	30	6.13	3.74	0.94	
Power Door	310	37,000	124	10.37	7.11	3.90	(R)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	1.35	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	2.70	
Compact Fluorescent	28	N/A	12	*	*	0.38	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$5.83	*	
Bronze Alloy GardCo	12	*	$0.24	
Concrete, Ornamental	35 or less	9.48	0.32	(R)
Steel, Painted Regular **	25	9.48	0.32	
Steel, Painted Regular **	30	10.26	0.34	
Steel, Unpainted 6-foot Mast Arm **	30	*	0.34	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.35	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.38	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.38	(R)
Wood, Laminated without Mast Arm	20	5.30	0.14	
Wood, Laminated Street Light Only	20	4.10	*	
Wood, Curved Laminated	30	6.84	0.25	(R)
Wood, Painted Underground	35	4.71	0.20	
Wood, Painted Street Light Only	35	4.71	*	

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	$11.63	$3.09	$1.01	(R)(I)
	165	12,000	60	14.21	4.06	1.89	
HADCO Techtra, QL	85	6,000	32	15.00	3.21	1.01	
	165	12,000	60	16.61	4.15	1.89	(I)

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Point of Delivery (POD)* is:

Distribution Charge	2.162 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 594
COMMUNICATION DEVICES ELECTRICITY SERVICE RIDER
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments that have communication devices with energy requirements not exceeding 25 line watts per unit, that are installed on streetlights and, or traffic signals served under Schedules 91 and, or 92.

CHARACTER OF SERVICE

60-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE*

The charge per Point of Delivery is:*

Distribution Charge	2.162 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments

The monthly kWh charge for service under this rider will be the number of units times estimated monthly usage determined using the following formula:

[((No. of Units x line watts per unit) x annual operating hours) / 1000] / 12

Where:
1) Annual operating hours are 8760
2) Line watts are based on the electrical data provided in the manufacturer's product specifications using the following criteria:

   [(110 nominal volts x rated amps) x percentage of operational rating]

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 715
ELECTRICAL EQUIPMENT SERVICES

PURPOSE

To provide construction and maintenance to Customer or utility owned electrical equipment (other than equipment owned by the Company).

AVAILABLE

In the State of Oregon.

APPLICABLE

To all Nonresidential Customers and utilities.

CHARACTER OF SERVICE

The Company provides engineering, electrical design and construction, equipment maintenance and repair, preventative diagnostic and prevention maintenance, electrical oil containment and compliance with the Environmental Protection Agency's Spill Prevention Control and Countermeasure Oil Program (SPCC), equipment leasing, Energy recovery and revenue protection and electrical equipment refurbishing and disposal services.

BILLING RATES

Service will be contractually negotiated.

SPECIAL CONDITIONS

(D)

1. Electrical Equipment Services will be provided in accordance with the Code of Conduct as set forth in OAR 860-038-0500 through 806-038-0640. (T)

2. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other electrical equipment services providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Electrical Equipment Services. (T)

TABLE 1
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2009 COS ONLY

		Forecast SJAN08E09		TOTAL ELECTRIC BILLS			
				CURRENT	PROPOSED	Change	
CATEGORY	RATE SCHEDULE	CUSTOMERS	MWH SALES	w/ Sch. 120, 125	w/ Sch. 120, 125	AMOUNT	PCT.
Residential	7	716,468	7,712,700	$764,308,478	$837,193,496	$72,885,017	9.5%
Employee Discount				($805,508)	($885,846)	($80,338)	
Subtotal				$763,502,971	$836,307,650	$72,804,679	9.5%
Outdoor Area Lighting	15	1,351	24,086	$4,365,082	$4,437,525	$72,443	1.7%
General Service <30 kW	32	83,657	1,500,066	$141,604,658	$152,523,546	$10,918,887	7.7%
Opt. Time-of-Day G.S. >30 kW	38	585	65,998	$6,292,121	$7,010,285	$718,164	11.4%
Irrig. & Drain. Pump. < 30 kW	47	3,167	21,962	$2,226,546	$2,619,889	$393,343	17.7%
Irrig. & Drain. Pump. > 30 kW	49	1,333	66,713	$4,827,237	$5,679,824	$852,588	17.7%
General Service >30 kW							
Secondary	83-S	12,596	5,442,588	$419,509,479	$451,413,782	$31,904,303	7.6%
Primary	83-P	143	275,761	$19,646,817	$21,433,742	$1,786,925	9.1%
Schedule 89 > 1 MW							
Secondary	89-S	103	681,975	$49,478,439	$53,986,765	$4,508,326	9.1%
Primary	89-P	104	1,838,582	$120,712,081	$132,620,273	$11,908,192	9.9%
Subtransmission	89-T	8	771,843	$46,848,376	$51,903,761	$5,055,385	10.8%
Street & Highway Lighting	91	206	104,772	$16,658,299	$17,062,237	$403,938	2.4%
Traffic Signals	92	17	5,001	$364,573	$424,935	$60,362	16.6%
Recreational Field Lighting	93	26	566	$86,536	$98,550	$12,014	13.9%
Communications Devices	94	1	240	$17,496	$20,393	$2,897	16.6%
TOTAL (CYCLE YEAR BASIS)		819,766	18,512,854	$1,596,140,711	$1,737,543,157	$141,402,446	8.9%
CONVERSION ADJUSTMENT				$1,594,047	$1,735,264		
TOTAL (CALENDAR YEAR BASIS)			18,531,343	**$1,597,734,758**	**$1,739,278,421**	**$141,543,663**	8.9%

TABLE 2
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2009 COS ONLY

CATEGORY	RATE SCHEDULE	Forecast SJAN08E09 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	716,468	7,712,700	$776,803,053	$837,039,242	$60,236,189	7.8%
Employee Discount				($832,650)	($895,599)	($62,949)	
Subtotal				$775,970,403	$836,143,643	$60,173,239	7.8%
Outdoor Area Lighting	15	1,351	24,086	$4,401,368	$4,428,529	$27,162	0.6%
General Service <30 kW	32	83,657	1,500,066	$144,304,530	$152,688,845	$8,384,315	5.8%
Opt. Time-of-Day G.S. >30 kW	38	585	65,998	$6,359,800	$6,986,887	$627,087	9.9%
Irrig. & Drain. Pump. < 30 kW	47	3,167	21,962	$2,304,512	$2,660,519	$356,007	15.4%
Irrig. & Drain. Pump. > 30 kW	49	1,333	66,713	$4,935,847	$5,700,374	$764,527	15.5%
General Service >30 kW							
Secondary	83-S	12,596	5,442,588	$421,310,990	$446,370,233	$25,059,244	5.9%
Primary	83-P	143	275,761	$19,760,950	$21,275,697	$1,514,747	7.7%
Schedule 89 > 1 MW							
Secondary	89-S	103	681,975	$49,435,283	$53,025,730	$3,590,446	7.3%
Primary	89-P	104	1,838,582	$119,945,540	$129,360,694	$9,415,154	7.8%
Subtransmission	89-T	8	771,843	$46,462,455	$50,437,259	$3,974,804	8.6%
Street & Highway Lighting	91	206	104,772	$16,791,359	$17,033,948	$242,589	1.4%
Traffic Signals	92	17	5,001	$365,273	$419,034	$53,761	14.7%
Recreational Field Lighting	93	26	566	$89,833	$100,985	$11,153	12.4%
Communications Devices	94	1	240	$17,530	$20,110	$2,580	14.7%
TOTAL (CYCLE YEAR BASIS)		819,766	18,512,854	$1,612,455,672	$1,726,652,488	$114,196,816	7.1%
CONVERSION ADJUSTMENT				$1,610,340	$1,724,387		
TOTAL (CALENDAR YEAR BASIS)			18,531,343	**$1,614,066,012**	**$1,728,376,875**	**$114,310,863**	7.1%

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 7, Residential Service

Net Monthly Bill

kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
50	$14.74	$15.15	2.7%
100	$18.69	$19.49	4.3%
200	$26.58	$28.19	6.1%
250	$30.52	$32.54	6.6%
300	$35.38	$37.80	6.8%
400	$45.10	$48.32	7.1%
500	$54.82	$58.84	7.3%
600	$64.54	$69.36	7.5%
700	$74.26	$79.89	7.6%
800	$83.97	$90.41	7.7%
900	$93.69	$100.93	7.7%
1,000	$103.41	$111.45	7.8%
1,100	$113.13	$121.98	7.8%
1,200	$122.85	$132.50	7.9%
1,300	$132.56	$143.02	7.9%
1,400	$142.28	$153.54	7.9%
1,500	$152.00	$164.07	7.9%
1,600	$161.72	$174.59	8.0%
1,700	$171.44	$185.11	8.0%
1,800	$181.15	$195.63	8.0%
2,000	$200.59	$216.68	8.0%
2,300	$229.74	$248.25	8.1%
2,750	$273.48	$295.60	8.1%
3,000	$297.77	$321.90	8.1%
3,500	$346.36	$374.52	8.1%
4,000	$394.95	$427.13	8.1%
4,500	$443.54	$479.74	8.2%
5,000	$492.13	$532.35	8.2%
7,500	$735.08	$795.42	8.2%
10,000	$978.03	$1,058.48	8.2%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 1-phase Service

Net Monthly Bill

kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
100	$21.64	$22.23	2.7%
500	$58.76	$61.73	5.1%
600	$68.04	$71.60	5.2%
700	$77.32	$81.48	5.4%
800	$86.60	$91.35	5.5%
900	$95.88	$101.23	5.6%
1,000	$105.16	$111.10	5.7%
1,500	$151.56	$160.47	5.9%
1,750	$174.76	$185.16	6.0%
2,000	$197.96	$209.84	6.0%
2,500	$244.36	$259.21	6.1%
3,500	$337.15	$357.95	6.2%
4,000	$383.55	$407.33	6.2%
4,500	$429.95	$456.70	6.2%
5,000	$476.35	$506.07	6.2%
6,000	$546.04	$579.98	6.2%
7,000	$615.72	$653.88	6.2%
8,000	$685.41	$727.79	6.2%
9,000	$755.09	$801.70	6.2%
10,000	$824.78	$875.61	6.2%
14,000	$1,103.52	$1,171.24	6.1%
15,000	$1,173.20	$1,245.15	6.1%
20,000	$1,521.63	$1,614.69	6.1%
21,900	$1,654.03	$1,755.11	6.1%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 32, 3-phase Service

Net Monthly Bill

kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
100	$25.76	$26.35	2.3%
500	$62.88	$65.85	4.7%
600	$72.16	$75.72	4.9%
700	$81.44	$85.60	5.1%
800	$90.72	$95.47	5.2%
900	$100.00	$105.35	5.3%
1,000	$109.28	$115.22	5.4%
1,500	$155.68	$164.59	5.7%
1,750	$178.88	$189.28	5.8%
2,000	$202.08	$213.96	5.9%
2,500	$248.48	$263.33	6.0%
3,500	$341.27	$362.07	6.1%
4,000	$387.67	$411.45	6.1%
4,500	$434.07	$460.82	6.2%
5,000	$480.47	$510.19	6.2%
6,000	$550.16	$584.10	6.2%
7,000	$619.84	$658.00	6.2%
8,000	$689.53	$731.91	6.1%
9,000	$759.21	$805.82	6.1%
10,000	$828.90	$879.73	6.1%
14,000	$1,107.64	$1,175.36	6.1%
15,000	$1,177.32	$1,249.27	6.1%
20,000	$1,525.75	$1,618.81	6.1%
21,900	$1,658.15	$1,759.23	6.1%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 47 Summer Period

Net Monthly Bill

kW	kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
10	50	$30.78	$31.61	2.7%
10	100	$35.80	$37.47	4.7%
10	500	$76.02	$84.36	11.0%
10	1,000	$115.98	$132.68	14.4%
10	2,000	$195.92	$229.31	17.0%
10	5,000	$435.72	$519.20	19.2%
20	100	$35.80	$37.47	4.7%
20	200	$45.86	$49.20	7.3%
20	500	$76.02	$84.36	11.0%
20	1,000	$126.28	$142.98	13.2%
20	2,000	$206.22	$239.61	16.2%
20	5,000	$446.02	$529.50	18.7%
20	8,000	$685.82	$819.39	19.5%
30	150	$40.83	$43.33	6.1%
30	500	$76.02	$84.36	11.0%
30	1,000	$126.28	$142.98	13.2%
30	3,000	$296.45	$346.54	16.9%
30	5,000	$456.32	$539.80	18.3%
30	8,000	$696.12	$829.69	19.2%
30	10,000	$855.99	$1,022.95	19.5%
30	15,000	$1,255.65	$1,506.10	19.9%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 49 Summer Period

Net Monthly Bill

Load Factor	kW	kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
20%	35	5,110	$410.78	$471.09	14.7%
40%	35	10,220	$754.60	$875.24	16.0%
60%	35	15,330	$1,098.43	$1,279.38	16.5%
80%	35	20,440	$1,442.26	$1,683.53	16.7%
20%	50	7,300	$573.58	$659.75	15.0%
40%	50	14,600	$1,064.76	$1,237.10	16.2%
60%	50	21,900	$1,555.95	$1,814.45	16.6%
80%	50	29,200	$2,047.13	$2,391.80	16.8%
20%	70	10,220	$790.65	$911.29	15.3%
40%	70	20,440	$1,478.31	$1,719.58	16.3%
60%	70	30,660	$2,165.96	$2,527.87	16.7%
80%	70	40,880	$2,853.62	$3,336.16	16.9%
20%	100	14,600	$1,116.26	$1,288.60	15.4%
40%	100	29,200	$2,098.63	$2,443.30	16.4%
60%	100	43,800	$3,080.99	$3,598.00	16.8%
80%	100	58,400	$4,063.36	$4,752.70	17.0%
20%	200	29,200	$2,201.63	$2,546.30	15.7%
40%	200	58,400	$4,166.36	$4,855.70	16.5%
60%	200	87,600	$6,131.08	$7,165.10	16.9%
80%	200	116,800	$8,095.81	$9,474.50	17.0%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
Effect of proposed rate change on Monthly Bills
Tariff Schedule 38, 3-phase Service
Bill comparison assumes 49% on-peak and 51% off-peak energy consumption

Net Monthly Bill

kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
1,000	$122.68	$132.50	8.0%
3,000	$316.54	$346.00	9.3%
5,000	$510.39	$559.49	9.6%
7,000	$704.25	$772.99	9.8%
10,000	$995.03	$1,093.24	9.9%
13,000	$1,285.82	$1,413.48	9.9%
14,000	$1,382.75	$1,520.23	9.9%
16,000	$1,576.61	$1,733.73	10.0%
21,000	$2,061.25	$2,267.47	10.0%
25,000	$2,448.96	$2,694.47	10.0%
30,000	$2,933.60	$3,228.21	10.0%
35,000	$3,418.25	$3,761.95	10.1%
40,000	$3,902.89	$4,295.69	10.1%
45,000	$4,387.53	$4,829.44	10.1%
50,000	$4,872.17	$5,363.18	10.1%
75,000	$7,295.39	$8,031.90	10.1%
100,000	$9,718.60	$10,700.61	10.1%
150,000	$14,565.02	$16,038.04	10.1%
200,000	$19,411.45	$21,375.47	10.1%
300,000	$29,104.30	$32,050.34	10.1%
400,000	$38,797.15	$42,725.20	10.1%
500,000	$48,490.00	$53,400.06	10.1%
750,000	$71,941.90	$79,306.99	10.2%
1,000,000	$95,913.95	$105,734.07	10.2%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Secondary, 3 phase service.

Net Monthly Bill

Load Factor	kW	kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
30%	30	6,570	$575.16	$614.41	6.8%
30%	50	10,950	$968.00	$1,023.33	5.7%
30%	100	21,900	$1,950.11	$2,045.62	4.9%
30%	300	65,700	$5,878.56	$6,134.80	4.4%
30%	500	109,500	$9,807.01	$10,223.98	4.3%
30%	750	164,250	$14,717.57	$15,335.46	4.2%
30%	1,000	219,000	$19,628.13	$20,446.93	4.2%
50%	30	10,950	$855.11	$915.79	7.1%
50%	50	18,250	$1,434.60	$1,525.64	6.3%
50%	100	36,500	$2,883.30	$3,050.24	5.8%
50%	300	109,500	$8,678.13	$9,148.66	5.4%
50%	500	182,500	$14,472.96	$15,247.08	5.3%
50%	750	273,750	$21,716.50	$22,870.11	5.3%
50%	1,000	365,000	$28,960.03	$30,493.13	5.3%
70%	30	15,330	$1,135.07	$1,217.18	7.2%
70%	50	25,550	$1,901.19	$2,027.95	6.7%
70%	100	51,100	$3,816.49	$4,054.86	6.2%
70%	300	153,300	$11,477.70	$12,162.52	6.0%
70%	500	255,500	$19,138.91	$20,270.18	5.9%
70%	750	383,250	$28,715.42	$30,404.76	5.9%
70%	1,000	511,000	$38,291.93	$40,539.34	5.9%
90%	30	19,710	$1,415.03	$1,518.57	7.3%
90%	50	32,850	$2,367.79	$2,530.26	6.9%
90%	100	65,700	$4,749.68	$5,059.48	6.5%
90%	300	197,100	$14,277.27	$15,176.38	6.3%
90%	500	328,500	$23,804.86	$25,293.28	6.3%
90%	750	492,750	$35,714.34	$37,939.41	6.2%
90%	1,000	657,000	$47,623.82	$50,585.54	6.2%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 83, Primary, 3 phase service.

Net Monthly Bill

Load Factor	kW	kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
30%	100	21,900	$1,919.58	$2,024.13	5.4%
30%	200	43,800	$3,746.45	$3,965.86	5.9%
30%	350	76,650	$6,486.76	$6,878.45	6.0%
30%	500	109,500	$9,227.08	$9,791.04	6.1%
30%	650	142,350	$11,967.39	$12,703.63	6.2%
30%	850	186,150	$15,621.14	$16,587.09	6.2%
30%	1,000	219,000	$18,361.45	$19,499.68	6.2%
50%	100	36,500	$2,812.01	$2,996.57	6.6%
50%	200	73,000	$5,531.32	$5,910.73	6.9%
50%	350	127,750	$9,610.29	$10,281.98	7.0%
50%	500	182,500	$13,689.26	$14,653.24	7.0%
50%	650	237,250	$17,768.23	$19,024.49	7.1%
50%	850	310,250	$23,206.85	$24,852.82	7.1%
50%	1,000	365,000	$27,285.82	$29,224.07	7.1%
70%	100	51,100	$3,704.45	$3,969.01	7.1%
70%	200	102,200	$7,316.20	$7,855.61	7.4%
70%	350	178,850	$12,733.82	$13,685.52	7.5%
70%	500	255,500	$18,151.44	$19,515.43	7.5%
70%	650	332,150	$23,569.06	$25,345.34	7.5%
70%	850	434,350	$30,792.56	$33,118.55	7.6%
70%	1,000	511,000	$36,210.18	$38,948.46	7.6%
90%	100	65,700	$4,596.89	$4,941.44	7.5%
90%	200	131,400	$9,101.07	$9,800.49	7.7%
90%	350	229,950	$15,857.35	$17,089.06	7.8%
90%	500	328,500	$22,613.63	$24,377.62	7.8%
90%	650	427,050	$29,369.90	$31,666.19	7.8%
90%	850	558,450	$38,378.27	$41,384.28	7.8%
90%	1,000	657,000	$45,134.55	$48,672.85	7.8%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Secondary
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
30%	1,000	219,000	$18,968.45	$20,175.83	6.0%
30%	2,000	438,000	$36,268.30	$38,703.66	6.7%
30%	4,000	876,000	$70,236.40	$75,127.72	7.0%
30%	7,500	1,642,500	$129,911.98	$139,101.22	7.1%
30%	10,000	2,190,000	$172,493.11	$184,752.29	7.1%
30%	15,000	3,285,000	$257,655.36	$276,054.44	7.1%
30%	20,000	4,380,000	$342,817.62	$367,356.58	7.2%
50%	1,000	365,000	$28,235.68	$30,096.91	6.6%
50%	2,000	730,000	$54,276.44	$58,019.50	6.9%
50%	4,000	1,460,000	$106,654.27	$114,160.99	7.0%
50%	7,500	2,737,500	$198,079.24	$212,172.36	7.1%
50%	10,000	3,650,000	$263,382.78	$282,180.49	7.1%
50%	15,000	5,475,000	$393,989.87	$422,196.73	7.2%
50%	20,000	7,300,000	$524,596.96	$562,212.97	7.2%
70%	1,000	511,000	$37,502.92	$40,018.00	6.7%
70%	2,000	1,022,000	$72,589.37	$77,640.14	7.0%
70%	4,000	2,044,000	$143,010.14	$153,132.27	7.1%
70%	7,500	3,832,500	$266,246.49	$285,243.51	7.1%
70%	10,000	5,110,000	$354,272.45	$379,608.68	7.2%
70%	15,000	7,665,000	$530,324.38	$568,339.02	7.2%
70%	20,000	10,220,000	$706,376.30	$757,069.36	7.2%
90%	1,000	657,000	$46,770.15	$49,939.08	6.8%
90%	2,000	1,314,000	$90,767.30	$97,125.77	7.0%
90%	4,000	2,628,000	$179,366.01	$192,103.55	7.1%
90%	7,500	4,927,500	$334,413.74	$358,314.66	7.1%
90%	10,000	6,570,000	$445,162.12	$477,036.87	7.2%
90%	15,000	9,855,000	$666,658.89	$714,481.31	7.2%
90%	20,000	13,140,000	$888,155.65	$951,925.75	7.2%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC

Effect of Proposed Rate Change on Monthly Bills

Tariff Schedule 89, Primary, 3 phase service.

Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

			Net Monthly Bill		
Load Factor	kW	kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
30%	1,000	219,000	$18,288.81	$19,467.33	6.4%
30%	2,000	438,000	$34,806.02	$37,214.56	6.9%
30%	4,000	876,000	$67,208.85	$72,077.42	7.2%
30%	7,500	1,642,500	$124,145.19	$133,318.82	7.4%
30%	10,000	2,190,000	$164,769.71	$177,018.39	7.4%
30%	15,000	3,285,000	$246,018.77	$264,417.54	7.5%
30%	20,000	4,380,000	$327,267.83	$351,816.68	7.5%
50%	1,000	365,000	$27,123.55	$29,019.08	7.0%
50%	2,000	730,000	$51,949.17	$55,791.73	7.4%
50%	4,000	1,460,000	$101,896.74	$109,633.36	7.6%
50%	7,500	2,737,500	$189,068.74	$203,619.97	7.7%
50%	10,000	3,650,000	$251,334.46	$270,753.25	7.7%
50%	15,000	5,475,000	$375,865.89	$405,019.83	7.8%
50%	20,000	7,300,000	$500,397.32	$539,286.41	7.8%
70%	1,000	511,000	$35,958.29	$38,570.83	7.3%
70%	2,000	1,022,000	$69,397.12	$74,673.70	7.6%
70%	4,000	2,044,000	$136,522.64	$147,127.31	7.8%
70%	7,500	3,832,500	$253,992.30	$273,921.11	7.8%
70%	10,000	5,110,000	$337,899.20	$364,488.12	7.9%
70%	15,000	7,665,000	$505,713.00	$545,622.12	7.9%
70%	20,000	10,220,000	$673,526.80	$726,756.13	7.9%
90%	1,000	657,000	$44,793.03	$48,122.58	7.4%
90%	2,000	1,314,000	$86,710.07	$93,420.68	7.7%
90%	4,000	2,628,000	$171,148.54	$184,621.25	7.9%
90%	7,500	4,927,500	$318,915.86	$344,222.26	7.9%
90%	10,000	6,570,000	$424,463.94	$458,222.98	8.0%
90%	15,000	9,855,000	$635,560.12	$686,224.42	8.0%
90%	20,000	13,140,000	$846,656.29	$914,225.85	8.0%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
Effect of Proposed Rate Change on Monthly Bills
Tariff Schedule 89, Transmission
Bill Comparison assumes 60% on-peak, 40% off-peak energy consumption

Net Monthly Bill

Load Factor	kW	kWh	Current Prices[1]	Proposed Prices[2]	Percent Difference
30%	4,000	876,000	$62,459.09	$67,484.35	8.0%
30%	5,000	1,095,000	$77,385.18	$83,679.64	8.1%
30%	10,000	2,190,000	$151,705.67	$164,346.08	8.3%
30%	20,000	4,380,000	$300,346.64	$325,678.95	8.4%
30%	40,000	8,760,000	$597,628.57	$648,344.70	8.5%
30%	50,000	10,950,000	$746,269.54	$809,677.58	8.5%
30%	70,000	15,330,000	$1,043,551.48	$1,132,343.33	8.5%
50%	4,000	1,460,000	$96,445.61	$104,415.92	8.3%
50%	5,000	1,825,000	$119,790.84	$129,766.60	8.3%
50%	10,000	3,650,000	$236,516.98	$256,519.99	8.5%
50%	20,000	7,300,000	$469,969.26	$510,026.79	8.5%
50%	40,000	14,600,000	$936,873.82	$1,017,040.37	8.6%
50%	50,000	18,250,000	$1,170,326.11	$1,270,547.17	8.6%
50%	70,000	25,550,000	$1,637,230.67	$1,777,560.75	8.6%
70%	4,000	2,044,000	$130,370.14	$141,285.48	8.4%
70%	5,000	2,555,000	$162,196.50	$175,853.56	8.4%
70%	10,000	5,110,000	$321,328.29	$348,693.91	8.5%
70%	20,000	10,220,000	$639,591.89	$694,374.62	8.6%
70%	40,000	20,440,000	$1,276,119.07	$1,385,736.04	8.6%
70%	50,000	25,550,000	$1,594,382.67	$1,731,416.75	8.6%
70%	70,000	35,770,000	$2,230,909.85	$2,422,778.17	8.6%
90%	4,000	2,628,000	$164,294.66	$178,155.05	8.4%
90%	5,000	3,285,000	$204,602.15	$221,940.51	8.5%
90%	10,000	6,570,000	$406,139.61	$440,867.83	8.6%
90%	20,000	13,140,000	$809,214.51	$878,722.45	8.6%
90%	40,000	26,280,000	$1,615,364.32	$1,754,431.71	8.6%
90%	50,000	32,850,000	$2,018,439.23	$2,192,286.34	8.6%
90%	70,000	45,990,000	$2,824,589.04	$3,067,995.59	8.6%

Notes:
1. Current prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111 and 140 prices.
2. Proposed prices include LIA and PPC charges, as well as estimates of Schedule 109, 110, 111, 140, 105 and 126 prices

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUT
SUMMARY - ALLOCATION OF 2009 COSTS TO RATE SCHEDULES ($000)

	Energy-Based Charges					Trans. & Related Charges			Distribution Demand & Facilities Charges				
Grouping	Power Supply	Franchise Fees	Trojan	Sch 129	Subtotal	Transmission	Ancillary Services	Subtotal	Substation	Subtrans.	13 kV Facilities	Connect Facilities	Subtotal
Schedule 7	$490,749	$19,483	$1,781		$21,264	$14,993	$2,341	$17,334	$34,796	$23,312	$62,945	$91,407	$212,459
Schedule 15	$1,411	$112	$6		$118	$23	$7	$30	$102	$68	$185	$45	$400
Schedule 32	$95,343	$3,609	$346		$3,955	$2,312	$455	$2,767	$6,279	$4,207	$9,475	$17,283	$37,243
Schedule 38	$4,185	$161	$15		$176	$45	$20	$65	$653	$438	$855	$441	$2,387
Schedule 47	$1,336	$57	$5		$62	$39	$6	$46	$265	$177	$341	$327	$1,110
Schedule 49	$4,081	$123	$15		$138	$117	$19	$137	$794	$532	$1,021	$447	$2,793
Schedule 83													
Secondary	$343,603	$10,772	$1,266	$10,274	$22,311							$13,865	$13,865
Primary	$16,839	$501	$62	$517	$1,080							$128	$128
Class Total						$9,290	$1,722	$11,012	$19,586	$13,122	$25,343		$58,051
Schedule 89 1-4 MW													
Secondary	$40,481	$1,249	$156	$1,268	$2,673							$643	$643
Primary	$43,390	$1,326	$172	$1,441	$2,939							$76	$76
Class Total						$2,158	$399	$2,557	$4,162	$2,789	$5,344		$12,295
Schedule 89 GT 4 MW													
Secondary	$2,736	$75	$9	$77	$162							$63	$63
Primary	$67,772	$3,592	$495	$4,151	$8,237							$107	$107
Subtransmission	$45,601	$1,998	$286	$2,388	$4,673							$699	$699
Class Total						$2,342	$555	$2,897	$5,231	$5,481	$1,403		$12,115
Schedule 91	$6,137	$432	$24		$457	$104	$29	$133	$444	$297	$803	$196	$1,740
Schedules 92 & 94	$324	$10	$1		$11	$6	$2	$8	$10	$7	$13	$33	$64
Schedule 93	$36	$2	$0		$2	$1	$0	$1	$4	$3	$5	$4	$15
Totals	$1,164,024	$43,502	$4,640	$20,115	$68,256	$31,430	$5,555	$36,985	$72,325	$50,433	$107,733	$125,764	$356,255

PORTLAND GENERAL ELECTRIC
RATE DESIGN INPUTS (CONTINUED)
SUMMARY - ALLOCATION OF 2009 COSTS TO RATE SCHEDULES ($000)

Grouping	Dist. Customer-Related		Metering		Billing		Other Consumer		Subtotal			
	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase	Fixed Costs	Subtotal
Schedule 7	$7,874	$20	$16,121	$11	$27,945	$18	$42,436	$28	$94,376	$77		$94,453
Schedule 15	$93		$0		$53		$86		$232	$0	$2,244	$2,476
Schedule 32	$650	$1,718	$1,186	$697	$2,029	$1,193	$3,502	$2,060	$7,368	$5,668		$13,036
Schedule 38	$4	$62	$1	$12	$2	$20	$9	$78	$17	$173		$190
Schedule 47	$9	$131	$5	$67	$8	$114	$14	$197	$35	$509		$544
Schedule 49	$0	$207	$0	$30	$0	$51	$1	$88	$1	$376		$377
Schedule 83												
Secondary	$66	$1,419	$18	$266	$32	$472	$209	$3,077	$325	$5,233		$5,558
Primary		$149		$3		$6		$37	$0	$195		$195
Schedule 89 1-4 MW												
Secondary		$18		$2		$7		$169	$0	$196		$196
Primary		$89		$2		$5		$138	$0	$234		$234
Schedule 89 GT 4 MW												
Secondary		$0		$0		$1		$3	$0	$4		$4
Primary		$31		$1		$10		$49	$0	$90		$90
Subtransmission		$232		$0		$3		$16	$0	$251		$251
Schedule 91	$653			$0	$96		$334		$1,083	$0	$7,501	$8,583
Schedules 92 & 94				$0	$8		$29		$37	$0		$37
Schedule 93		$41		$1		$1		$2	$0	$44		$44
Totals	$9,350	$4,117	$17,331	$1,091	$30,174	$1,901	$46,619	$5,942	$103,474	$13,051	$9,745	$126,270

PORTLAND GENERAL ELECTRIC
RATE DESIGN
2009

Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 7						
Residential						
Theoretic						
Functional Costs						
Basic Charge						
Single-Phase	$94,376	715,997	Customers	$10.98	per cust. per mo.	$94,340
Three-Phase	$77	472	Customers	$13.64	per cust. per mo.	$77
Trans. & Rel. Serv. Charge	$17,334	7,712,700	MWh	2.25	mills/kWh	$17,354
Distribution Charge	$212,459	7,712,700	MWh	27.55	mills/kWh	$212,485
Franchise Fees & Other	$21,264	7,712,700	MWh	2.76	mills/kWh	$21,287
Energy Charge	$490,749	7,712,700	MWh	63.63	mills/kWh	$490,759
Subtotal	$836,259					$836,302
Proposed						
Functional Costs						
Basic Charge						
Single-Phase		715,997	Customers	$10.00	per cust. per mo.	$85,920
Three-Phase		472	Customers	$13.00	per cust. per mo.	$74
Trans. & Rel. Serv. Charge		7,712,700	MWh	2.25	mills/kWh	$17,354
Distribution Charge		7,712,700	MWh	28.64	mills/kWh	$220,892
System Usage Charge Calculation						
Franchise Fees & Other		7,712,700	MWh	2.76	mills/kWh	$21,287
Cust Impact Offset		7,712,700	MWh	0.12	mills/kWh	$926
System Usage Charge		7,712,700	MWh	2.88	mills/kWh	$22,213
Energy Charge						
Block 1		2,077,938	MWh	50.66	mills/kWh	$105,268
Block 2		5,634,762	MWh	68.41	mills/kWh	$385,474
Subtotal						$837,193
					w/o CIO	$836,268
SCHEDULE 15						
Outdoor Area Lighting						
Theoretic						
Functional Costs						
Basic Charge	$232	1,351	Customers	$14.29	per cust. per mo.	$232
Trans. & Rel. Serv. Charge	$30	24,086	MWh	1.25	mills/kWh	$30
Distribution Charge	$400	24,086	MWh	16.62	mills/kWh	$400
Franchise Fees & Other	$118	24,086	MWh	4.88	mills/kWh	$118
Energy Charge	$1,411	24,086	MWh	58.57	mills/kWh	$1,411
Fixed Charges	$2,244	24,086	MWh			$2,244
Subtotal	$4,435					$4,435
Proposed						
Functional Costs						
Trans. & Rel. Serv. Charge		24,086	MWh	1.25	mills/kWh	$30
Distribution Charge		24,086	MWh	26.24	mills/kWh	$632
System Usage Charge Calc						
Franchise Fees & Other		24,086	MWh	4.88	mills/kWh	$118
Cust Impact Offset		24,086	MWh	0.12	mills/kWh	$3
System Usage Charge		24,086	MWh	5.00	mills/kWh	$120
Energy Charge		24,086	MWh	58.57	mills/kWh	$1,411
Fixed Charges		24,086	MWh			$2,244
Subtotal						$4,438
					w/o CIO	$4,435

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 32						
General Service <30 kW						
Theoretic						
Functional Costs						
Basic Charge						
Single-Phase	$7,368	52,679	Customers	$11.66	per cust. per mo.	$7,371
Three-Phase	$5,668	30,977	Customers	$15.25	per cust. per mo.	$5,669
Trans. & Rel. Serv. Charge	$2,767	1,500,066	MWh	1.84	mills/kWh	$2,760
Distribution Charge	$37,243	1,500,066	MWh	24.83	mills/kWh	$37,247
Franchise Fees & Other	$3,955	1,500,066	MWh	2.64	mills/kWh	$3,960
Energy Charge	$95,343	1,500,066	MWh	63.56	mills/kWh	$95,344
Subtotal	$152,344					$152,351
Proposed						
Functional Costs						
Basic Charge						
Single-Phase		52,679	Customers	$12.00	per cust. per mo.	$7,586
Three-Phase		30,977	Customers	$16.00	per cust. per mo.	$5,948
Trans. & Rel. Serv. Charge		1,500,066	MWh	1.84	mills/kWh	$2,760
Distribution Charge						
First 5 MWh		1,337,428	MWh	27.11	mills/kWh	$36,258
Over 5 MWh		162,637	MWh	3.00	mills/kWh	$488
System Usage Charge Calc						
Franchise Fees & Other		1,500,066	MWh	2.64	mills/kWh	$3,960
Cust Impact Offset		1,500,066	MWh	0.12	mills/kWh	$180
System Usage Charge		1,500,066	MWh	2.76	mills/kWh	$4,140
Energy Charge		1,500,066	MWh	63.56	mills/kWh	$95,344
Subtotal						$152,524
					w/o CIO	$152,344
SCHEDULE 38						
Time-of-Day G.S. >30 kW						
Theoretic						
Functional Costs						
Basic						
Single-Phase	$17	61	Customers	$23.61	per cust. per mo.	$17
Three-Phase	$173	524	Customers	$27.41	per cust. per mo.	$172
Trans. & Rel. Serv. Charge	$65	65,998	MWh	0.99	per cust. per mo.	$65
Distribution Charges	$2,387	65,998	MWh	36.16	per cust. per mo.	$2,386
Franchise Fees & Other	$176	65,998	MWh	2.66	mills/kWh	$176
Energy Charge	$4,185	65,998	MWh	63.41	mills/kWh	$4,185
Subtotal	$7,002					$7,002
Proposed						
Functional Costs						
Basic						
Single-Phase		61	Customers	$20.00	per cust. per mo.	$15
Three-Phase		524	Customers	$25.00	per cust. per mo.	$157
Trans. & Rel. Serv. Charge		65,998	MWh	0.99	mills/kWh	$65
Distribution Charges		65,998	MWh	35.97	mills/kWh	$2,374
System Usage Charge						
Franchise Fees & Other		65,998	MWh	2.66	mills/kWh	$176
Cust Impact Offset		65,998	MWh	0.12	mills/kWh	$8
System Usage Charge		65,998	MWh	2.78	mills/kWh	$183
Energy Charge Calc						
On-Peak (special)		31,815	MWh	70.97	mills/kWh	$2,258
Off-Peak		34,183	MWh	56.37	mills/kWh	$1,927
Reactive Demand Charge		61,602	kVar	$0.50	kVar	$31
Subtotal						$7,010
					w/o CIO	$7,002

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 47						
Irrig. & Drain. Pump. - < 30 kW						
Theoretic						
Functional Costs						
Basic Charge						
Single-Phase	$35	206	Customers	$28.32	per cust. per summ. mo.	$35
Three-Phase	$509	2,961	Customers	$28.63	per cust. per summ. mo.	$509
Trans. & Rel. Serv. Charge	$46	21,962	MWh	2.08	mills/kWh	$46
Distribution Charges	$1,110	21,962	MWh	50.55	mills/kWh	$1,110
Franchise Fees & Other	$62	21,962	MWh	2.82	mills/kWh	$62
Energy Charge	$1,336	21,962	MWh	60.85	mills/kWh	$1,336
Subtotal	$3,098					$3,098
Proposed						
Functional Costs						
Basic Charge						
Single-Phase		206	Customers	$25.00	per cust. per summ. mo.	$31
Three-Phase		2,961	Customers	$25.00	per cust. per summ. mo.	$444
Trans. & Rel. Serv. Charge		21,962	MWh	2.08	mills/kWh	$46
Distribution Charge Calc						
First 50 kWh per kW		6,787	MWh	67.49	mills/kWh	$458
Over 50 kWh per kW		15,175	MWh	47.49	mills/kWh	$721
System Usage Charge Calc						
Franchise Fees & Other		21,962	MWh	2.82	mills/kWh	$62
Cust Impact Offset		21,962	MWh	(21.76)	mills/kWh	($478)
System Usage Charge		21,962	MWh	(18.94)	mills/kWh	($416)
Energy Charge		21,962	MWh	60.85	mills/kWh	$1,336
Reactive Demand Charge		0	kVar	$0.50	kVar	$0
Subtotal with Consumer Impact Offset						$2,620
					w/o CIO	$3,098
SCHEDULE 49						
Irrig. & Drain. Pump. - > 30 kW						
Theoretic						
Functional Costs						
Basic						
Single-Phase	$1	8	Customers	$28.34	per cust. per summ. mo.	$1
Three-Phase	$376	1,325	Customers	$47.27	per cust. per summ. mo.	$376
Trans. & Rel. Serv. Charge	$137	66,713	MWh	2.05	mills/kWh	$137
Distribution Charges	$2,793	66,713	MWh	41.86	mills/kWh	$2,793
Franchise Fees & Other	$138	66,713	MWh	2.08	mills/kWh	$139
Energy Charge	$4,081	66,713	MWh	61.18	mills/kWh	$4,081
Subtotal	$7,527					$7,527
Proposed						
Functional Costs						
Basic Charge						
Single-Phase		8	Customers	$30.00	per cust. per summ. mo.	$1
Three-Phase		1,325	Customers	$30.00	per cust. per summ. mo.	$239
Trans. & Rel. Serv. Charge		66,713	MWh	2.05	mills/kWh	$137
Distribution Charge Calc						
First 50 kWh per kW		18,400	MWh	58.37	mills/kWh	$1,074
Over 50 kWh per kW		48,313	MWh	38.37	mills/kWh	$1,854
System Usage Charge Calc						
Franchise Fees & Other		66,713	MWh	2.08	mills/kWh	$139
Cust Impact Offset		66,713	MWh	(27.69)	mills/kWh	($1,847)
System Usage Charge		66,713	MWh	(25.61)	mills/kWh	($1,709)
Energy Charge		66,713	MWh	61.18	mills/kWh	$4,081
Reactive Demand Charge		4,798	kVar	$0.50	kVar	$2
Subtotal with Consumer Impact Offset						$5,680
					w/o CIO	$7,527

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 83						
General Service 31-1,000 kW						
Theoretic						
Functional Costs				68%		
Basic Charge						
Single-Phase Secondary	$325	801	Customers	$33.77	per cust, per mo.	$325
Three-Phase Secondary	$5,233	11,808	Customers	$36.93	per cust, per mo.	$5,233
Primary	$195	143	Customers	$114.04	per cust, per mo.	$195
Transmission & Related Service Charge	$11,012	15,495,047	kW demand	$0.71	per kW demand	$11,001
Distribution Charges						
13 kV Facilities	$25,343	18,548,463	kW faccap	$1.37	per kW faccap	$25,411
Connect Charge	$13,993	18,548,463	kW faccap	$0.75	per kW faccap	$13,911
Subtransmission Charge	$13,122	15,575,321	kW demand	$0.84	per kW demand	$13,083
Substation Charge	$19,586	15,575,321	kW demand	$1.26	per kW demand	$19,625
Secondary Franchise Fees & Other	$22,311	5,481,948	MWh	4.07	mills/kWh	$22,312
Primary Franchise Fees & Other	$1,080	275,761	MWh	3.91	mills/kWh	$1,078
Secondary COS Energy Charge	$343,603	5,442,588	MWh	63.13	mills/kWh	$343,591
Primary COS Energy Charge	$16,839	275,761	MWh	61.06	mills/kWh	$16,838
Subtotal	$472,642					$472,603
Proposed						
Functional Costs						
Basic Charge						
Secondary Single-Phase		801	Customers	$20.00	per cust, per mo.	$192
Secondary Three-Phase		11,808	Customers	$25.00	per cust, per mo.	$3,542
Primary		143	Customers	$80.00	per cust, per mo.	$137
Trans. & Rel. Serv. Charge						
First 30 kW		4,410,599	kW demand	$0.75	per kW demand	$3,308
Over 30 kW		11,084,448	kW demand	$0.75	per kW demand	$8,313
Distribution Charges						
Secondary Facilities Charge						
First 30 kW		4,539,432	kW faccap	$1.54	<= 30 kW faccap	$6,991
Over 30 kW		13,229,074	kW faccap	$2.34	> 30 kW faccap	$30,956
Primary Facilities Charge						
First 30 kW		51,360	kW faccap	$1.81	<= 30 kW faccap	$93
Over 30 kW		728,598	kW faccap	$1.81	> 30 kW faccap	$1,319
Secondary Demand Charge						
First 30 kW		4,363,870	kW demand	$2.13	per kW demand	$9,295
Over 30 kW		10,561,013	kW demand	$2.13	per kW demand	$22,495
Primary Demand Charge						
First 30 kW		51,261	kW demand	$2.13	per kW demand	$109
Over 30 kW		599,177	kW demand	$2.13	per kW demand	$1,276
Secondary System Usage Charge Calc						
Franchise Fees & Other		5,481,948	MWh	4.07	mills/kWh	$22,312
Cust Impact Offset		5,481,948	MWh	0.12	mills/kWh	$658
System Usage Charge		5,481,948	MWh	4.19	mills/kWh	$22,969
Primary System Usage Charge Calc						
Franchise Fees & Other		275,761	MWh	3.91	mills/kWh	$1,078
Cust Impact Offset		275,761	MWh	0.12	mills/kWh	$33
System Usage Charge		275,761	MWh	4.03	mills/kWh	$1,111
Secondary COS Energy Charge		5,442,588	MWh	63.13	mills/kWh	$343,591
Primary COS Energy Charge		275,761	MWh	61.06	mills/kWh	$16,838
Reactive Demand Charge		1,739,215	kVar	$0.50	kVar	$870
Subtotal						$473,406
					w/o CIO	$472,715

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 89						
General Service 1,001-4,000 kW						
Theoretic						
Functional Costs						
Secondary Basic Charge	$196	104	Customers	$156.31	per cust, per mo.	$196
Primary Basic Charge	$234	85	Customers	$229.27	per cust, per mo.	$234
Transmission & Related Service Charge	$2,557	3,034,027	kW on-peak	$0.84	per kW on-peak demand	$2,549
Distribution Charges						
13 kV Facilities Charge	$5,344	3,762,776	kW faccap	$1.42	per kW faccap	$5,343
Connect Charges	$719	3,762,776	kW faccap	$0.19	per kW faccap	$715
Subtransmission Demand Charge	$2,789	3,187,201	kW on-peak	$0.87	per kW on-peak demand	$2,773
Substation Demand Charge	$4,162	3,187,201	kW on-peak	$1.31	per kW on-peak demand	$4,175
Secondary Franchise Fees & Other	$2,673	676,491	MWh	3.95	mills/kWh	$2,672
Primary Franchise Fees & Other	$2,939	768,781	MWh	3.82	mills/kWh	$2,937
Secondary COS Energy Charge	$40,481	641,022	MWh	63.15	mills/kWh	$40,481
Primary COS Energy Charge	$43,390	716,441	MWh	60.56	mills/kWh	$43,388
Subtotal	$105,484					$105,462
Proposed						
Functional Costs						
Secondary Basic Charge		104	Customers	$160.00	per cust, per mo.	$200
Primary Basic Charge		85	Customers	$230.00	per cust, per mo.	$235
Trans. & Rel. Serv. Charge		3,034,027	kW on-peak	$0.75	per kW on-peak demand	$2,276
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		1,251,434	kW faccap	$2.05	per kW faccap	$2,565
1,001-4,000 kW		614,015	kW faccap	$0.61	per kW faccap	$375
Primary Facilities Charge						
First 1,000 kW		1,022,000	kW faccap	$1.83	per kW faccap	$1,870
1,001-4,000 kW		875,327	kW faccap	$0.39	per kW faccap	$341
Demand Charge		3,187,201	kW on-peak	$2.18	per kW on-peak demand	$6,948
Secondary System Usage Charge Calc						
Franchise Fees & Other		676,491	MWh	3.95	mills/kWh	$2,672
Cust Impact Offset		676,491	MWh	0.12	mills/kWh	$81
System Usage Charge		676,491	MWh	4.07	mills/kWh	$2,753
Primary System Usage Charge Calc						
Franchise Fees & Other		768,781	MWh	3.75	mills/kWh	$2,883
Cust Impact Offset		768,781	MWh	0.12	mills/kWh	$92
System Usage Charge		768,781	MWh	3.87	mills/kWh	$2,975
Secondary Energy Charge						
On-peak		415,674	MWh	68.65	mills/kWh	$28,536
Off-peak		225,348	MWh	53.67	mills/kWh	$12,094
Primary Energy Charge						
On-peak		444,958	MWh	66.18	mills/kWh	$29,447
Off-peak		271,483	MWh	51.71	mills/kWh	$14,038
Reactive Demand Charge		650,336	kVar	$0.50	kVar	$325
Subtotal						$104,980
					w/o CIO	$104,807

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 89						
General Service 4,000 plus kW						
Theoretic						
Functional Costs						
Secondary Basic Charge	$4	2	Customers	$177.53	per cust, per mo.	$4
Primary Basic Charge	$90	30	Customers	$250.49	per cust, per mo.	$90
Subtransmission Basic Charge	$251	10	Customers	$2,094.82	per cust, per mo.	$251
Transmission & Related Service Charge	$2,897	3,398,155	kW on-peak	$0.85	per kW on-peak demand	$2,888
Distribution Charges						
13 kV Facilities Charge	$1,403	4,102,189	kW faccap	$0.34	per kW faccap	$1,395
Connect Charges	$869	6,866,126	kW faccap	$0.13	per kW faccap	$893
Subtransmission Demand Charge	$5,481	5,870,052	kW on-peak	$0.93	per kW faccap	$5,459
Substation Demand Charge	$5,231	3,724,724	kW on-peak	$1.40	per kW on-peak demand	$5,215
Secondary Franchise Fees & Other	$162	40,953	MWh	3.94	mills/kWh	$161
Primary Franchise Fees & Other	$8,237	2,214,831	MWh	3.72	mills/kWh	$8,239
Subtransmission Franchise Fees & Other	$4,673	1,299,267	MWh	3.60	mills/kWh	$4,677
Secondary COS Energy Charge	$2,736	40,953	MWh	66.82	mills/kWh	$2,736
Primary COS Energy Charge	$67,772	1,122,141	MWh	60.39	mills/kWh	$67,766
Subtransmission COS Energy Charge	$45,601	771,843	MWh	59.08	mills/kWh	$45,601
Subtotal	$145,406					$145,376
Proposed						
Functional Costs						
Secondary Basic Charge		2	Customers	$160.00	per cust, per mo.	$4
Primary Basic Charge		30	Customers	$230.00	per cust, per mo.	$83
Subtransmission Basic Charge		10	Customers	$1,000.00	per cust, per mo.	$120
Trans. & Rel. Serv. Charge		3,398,155	kW on-peak	$0.75	per kW on-peak demand	$2,549
Distribution Charges						
Secondary Facilities Charge						
First 1,000 kW		24,000	kW faccap	$2.05	per kW faccap	$49
1,001-4,000 kW		61,380	kW faccap	$0.61	per kW faccap	$37
Greater than 4,000 kW		74,168	kW faccap	$0.61	per kW faccap	$45
Primary Facilities Charge						
First 1,000 kW		360,000	kW faccap	$1.83	per kW faccap	$659
1,001-4,000 kW		1,066,165	kW faccap	$0.39	per kW faccap	$416
Greater than 4,000 kW		2,516,476	kW faccap	$0.39	per kW faccap	$981
Subtransmission Facilities Charge						
First 1,000 kW		120,000	kW faccap	$1.83	per kW faccap	$220
1,001-4,000 kW		360,000	kW faccap	$0.39	per kW faccap	$140
Greater than 4,000 kW		2,283,937	kW faccap	$0.39	per kW faccap	$891
Secondary & Primary Demand Charge		3,724,724	kW on-peak	$2.18	per kW on-peak demand	$8,120
Subtransmission Demand Charge		2,145,328	kW on-peak	$1.10	per kW on-peak demand	$2,360
Secondary System Usage Charge Calc						
Franchise Fees & Other		40,953	MWh	3.95	mills/kWh	$162
Cust Impact Offset		40,953	MWh	0.12	mills/kWh	$5
System Usage Charge		40,953	MWh	4.07	mills/kWh	$167
Primary System Usage Charge Calc						
Franchise Fees & Other		2,214,831	MWh	3.75	mills/kWh	$8,306
Cust Impact Offset		2,214,831	MWh	0.12	mills/kWh	$266
System Usage Charge		2,214,831	MWh	3.87	mills/kWh	$8,571
Subtransmission System Usage Charge Calc						
Franchise Fees & Other		1,299,267	MWh	3.60	mills/kWh	$4,677
Cust Impact Offset		1,299,267	MWh	0.12	mills/kWh	$156
System Usage Charge		1,299,267	MWh	3.72	mills/kWh	$4,833
Secondary Energy Charge						
On-peak		25,998	MWh	68.65	mills/kWh	$1,785
Off-peak		14,955	MWh	53.67	mills/kWh	$803
Primary Energy Charge						
On-peak		666,649	MWh	66.18	mills/kWh	$44,119
Off-peak		455,493	MWh	51.71	mills/kWh	$23,554
Subtransmission Energy Charge						
On-peak		441,805	MWh	65.19	mills/kWh	$28,801
Off-peak		330,038	MWh	50.90	mills/kWh	$16,799
Reactive Demand Charge		798,806	kVar	$0.50	kVar	$399
Subtotal						$146,504
					w/o CIO	$146,078
Total Schedule 89 Allocations	$250,891			Schedule 89 Revenues w/o CIO		$250,885

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Schedule	Allocated Inputs ($000)	Billing Determinants Amount	Billing Determinants Unit	Rate	Rate Unit	Annual Revenue ($000)
SCHEDULE 91						
Street & Highway Lighting						
Theoretic						
Functional Costs						
Basic Charge	$1,083	206	Customers	$437.95	per cust, per mo.	$1,083
Trans. & Rel. Serv. Charge	$133	104,772	MWh	1.27	mills/kWh	$133
Distribution Charge	$1,740	104,772	MWh	16.61	mills/kWh	$1,740
Franchise Fees & Other	$457	104,772	MWh	4.36	mills/kWh	$457
COS Energy Charge	$6,137	104,772	MWh	58.57	mills/kWh	$6,136
Fixed Charges	$7,501					$7,501
Subtotal	$17,050					$17,050
Proposed						
Functional Costs						
Trans. & Rel. Serv. Charge		104,772	MWh	1.27	mills/kWh	$133
Distribution Charge		104,772	MWh	26.94	mills/kWh	$2,823
System Usage Charge Calc						
Franchise Fees & Other		104,772	MWh	4.36	mills/kWh	$457
Cust Impact Offset		104,772	MWh	0.12	mills/kWh	$13
System Usage Charge		104,772	MWh	4.48	mills/kWh	$469
COS Energy Charge		104,772	MWh	58.57	mills/kWh	$6,136
Fixed Charges		104,772	MWh			$7,501
Subtotal						$17,062
					w/o CIO	$17,050
SCHEDULES 92 & 94						
Traffic Signals & Communication Devices						
Theoretic						
Functional Costs						
Basic Charge	$37	18	Customers	$173.59	per cust, per mo.	$37
Trans. & Rel. Serv. Charge	$8	5,241	MWh	1.44	mills/kWh	$8
Distribution Charge	$64	5,241	MWh	12.25	mills/kWh	$64
Franchise Fees & Other	$11	5,241	MWh	2.09	mills/kWh	$11
COS Energy Charge	$324	5,241	MWh	61.91	mills/kWh	$324
Subtotal	$445					$445
Proposed						
Functional Costs						
Trans. & Rel. Serv. Charge		5,241	MWh	1.44	mills/kWh	$8
Distribution Charge		5,241	MWh	19.41	mills/kWh	$102
System Usage Charge Calc						
Franchise Fees & Other		5,241	MWh	2.09	mills/kWh	$11
Cust Impact Offset		5,241	MWh	0.12	mills/kWh	$1
System Usage Charge		5,241	MWh	2.21	mills/kWh	$12
COS Energy Charge		5,241	MWh	61.91	mills/kWh	$324
Subtotal						$445
					w/o CIO	$445
SCHEDULE 93						
Recreational Field Lighting						
Theoretic						
Functional Costs						
Basic Charge	$44	26	Customers	$141.45	per cust, per mo.	$44
Trans. & Rel. Serv. Charge	$1	566	MWh	1.80	mills/kWh	$1
Distribution Charge	$15	566	MWh	27.02	mills/kWh	$15
Franchise Fees & Other	$2	566	MWh	4.13	mills/kWh	$2
Energy Charge	$36	566	MWh	63.00	mills/kWh	$36
Subtotal	$98					$98
Proposed						
Functional Costs						
Basic Charge		26	Customers	$30.00	per cust, per mo.	$9
Trans. & Rel. Serv. Charge		566	MWh	1.80	mills/kWh	$1
Distribution Charge		566	MWh	88.41	mills/kWh	$50
System Usage Charge Calc						
Franchise Fees & Other		566	MWh	4.13	mills/kWh	$2
Cust Impact Offset		566	MWh	0.12		$0
System Usage Charge		566	MWh	4.25	mills/kWh	$2
Energy Charge		566	MWh	63.00	mills/kWh	$36
Subtotal						$99
					w/o CIO	$98

PORTLAND GENERAL ELECTRIC
CONSUMER IMPACT OFFSET

Grouping	Cycle MWH	Revenues at 2008 Prices ($000)	2009 Allocated Costs ($000)	Percent Change	Maximum Change	Impact Offset Cap	Impact Offset MWH	CIO mills/kWh	CIO Revenues
Schedule 7	7,712,700	$764,308	$836,259	9.4%	17.7%	$0	0	0.12	$926
Schedule 15	24,086	$4,365	$4,435	1.6%	17.7%	$0	0	0.12	$3
Schedule 32	1,500,066	$141,605	$152,344	7.6%	17.7%	$0	0	0.12	$180
Schedule 38	65,998	$6,292	$7,002	11.3%	17.7%	$0	0	0.12	$8
Schedule 47	21,962	$2,227	$3,098	39.1%	17.7%	($478)	21,962	(21.76)	($478)
Schedule 49	66,713	$4,827	$7,527	55.9%	17.7%	($1,847)	66,713	(27.69)	($1,847)
Schedule 83	5,718,349	$439,742	$472,589	7.5%	17.7%	$0	0	0.12	$686
Schedule 89	3,292,401	$229,172	$250,891	9.5%	17.7%	$0	0	0.12	$395
Schedule 91	104,772	$16,658	$17,050	2.4%	17.7%	$0	0	0.12	$13
Schedule 92 & 94	5,241	$382	$445	16.4%	17.7%	$0	0	0.12	$1
Schedule 93	566	$87	$98	13.8%	17.7%	$0	0	0.12	$0
COS TOTALS	18,512,854	$1,609,666	$1,751,737	8.8%	17.7%	($2,325)	88,675		
Non-COS Energy	1,747,282							0.12	$210
Total Cycle Energy	20,260,137								
TOTAL CIO REVENUES									$95

Cap on Rate Change	2.0	times change from 2008 prices
Cap on CIO (mills/kWh)	(30.00)	mills/kWh

PORTLAND GENERAL ELECTRIC

Schedule 128
Summary of Annual Transition Adjustments

Schedules	COS Tariff Energy Price mills/kWh	Market Value of Energy mills/kWh	Annual Transition Adjustment mills/kWh
Schedule 515	58.57	66.79	(8.22)
Schedule 532	63.56	72.47	(8.91)
Schedule 538	63.41	72.30	(8.89)
Schedule 549	61.18	69.76	(8.58)
Schedule 83/583-S	63.13	71.98	(8.85)
Schedule 89/589-S			
On-peak	68.65	78.27	(9.62)
Off-peak	53.67	61.20	(7.53)
Schedule 83/583-P	61.06	69.63	(8.57)
Schedule 89/589-P			
On-peak	66.18	75.46	(9.28)
Off-peak	51.71	58.97	(7.26)
Schedule 89/589-T			
On-peak	65.19	74.33	(9.14)
Off-peak	50.90	58.04	(7.14)
Schedule 91/591	58.57	66.79	(8.22)
Schedule 592/594	61.91	70.59	(8.68)

PORTLAND GENERAL ELECTRIC
2009 Test Period Functionalized Revenue Requirement

FUNCTION	AMOUNT	ADJUST	TOTAL
PRODUCTION	$1,165,195	$20,215	$1,185,410
TRANSMISSION	$31,462		$31,462
ANCILLARY	$5,562		$5,562
DISTRIBUTION	$427,296	$886	$428,182
METERING	$18,447		$18,447
BILLING	$32,118		$32,118
CONSUMER	$52,631		$52,631
TOTALS	$1,732,711		$1,753,811

Note: Distribution adjustment is employee discount
Note: Production adjustment is Schedule 129 Long-Term Transition Adjustment

PORTLAND GENERAL ELECTRIC
UNBUNDLED 2009 COSTS ($000)

	Unbundled Costs	Adjusted to Cycle
Fixed Generation Revenue Requirement	$358,496	$358,135
Net Variable Power Costs	$806,699	$805,889
Production Costs	$1,165,195	$1,164,024
Ancillary Services	$5,562	$5,555
Transmission	$31,462	$31,430
Distribution Services	$427,296	
Franchise Fees	($43,560)	
Trojan Decommissioning	($4,646)	
Employee Discount	$886	$885
Distribution Costs	$379,976	$379,467
Consumer Services		
Metering Services	$18,447	$18,422
Billing Services	$32,118	$32,075
Other Consumer Services	$52,631	$52,561
Franchise Fees	$43,560	$43,502
Trojan Decommissioning	$4,646	$4,640
Schedule 129	$20,215	$20,115
Totals	$1,753,811	$1,751,790
Net of employee discount	$1,752,926	$1,750,905
Net of Sch 129	$1,732,711	$1,730,790
Calendar MWH	20,287,302	
Cycle MWH	20,260,137	
Cycle/Cal Ratio	99.87%	
COS Calendar Energy MWH	18,531,583	
COS Cycle MWH	18,512,854	
Cycle/Cal Ratio	99.90%	

PORTLAND GENERAL ELECTRIC
Changes in Revenues Resulting from 2009 Price Changes ($000)

Category	2008 Current	2009 Proposed	Change
Table 1 COS	$1,596,141	$1,737,543	$141,402
DA/76R	($11,079)	($6,583)	$4,496
Cycle Totals	$1,585,062	$1,730,961	$145,899
Calendar Adjustment	1.00111		
Calendar Basis Retail Revenues	$1,586,821	$1,732,882	$146,061

Reconciliation of Revenues and Revenue Requirement

Revenue Requirement	$1,732,711
Calendar Revenues	$1,732,882
Base Rate Delta	$171

PORTLAND GENERAL ELECTRIC
ALLOCATION OF PRODUCTION COSTS TO COS CUSTOMERS
2009

Grouping	Marginal Power Costs ($000)	COS Calendar Energy	Marginal Unit Cost $/MWH	Allocation Percent	Allocated Production Costs ($000)	Embedded Unit Cost $/MWH	Cycle Basis Costs ($000)
Schedule 7	$559,896	7,717,343	72.55	42.14%	$491,044	$63.63	$490,749
Schedule 15	$1,609	24,086	66.79	0.12%	$1,411	$58.57	$1,411
Schedule 32	$108,819	1,501,556	72.47	8.19%	$95,438	$63.56	$95,343
Schedule 38							
On-peak	$3,170	40,238	78.78	0.24%	$2,780	$69.09	$2,785
Off-peak	$1,593	25,638	62.14	0.12%	$1,397	$54.49	$1,400
Schedule 47	$1,539	22,185	69.38	0.12%	$1,350	$60.85	$1,336
Schedule 49	$4,639	66,495	69.76	0.35%	$4,068	$61.18	$4,081
Schedule 83-S	$392,447	5,451,834	71.98	29.54%	$344,187	$63.13	$343,603
Schedule 89-S 1-4 MW							
On-peak	$32,308	414,388	77.97	2.43%	$28,335	$68.38	$28,425
Off-peak	$13,703	224,619	61.01	1.03%	$12,018	$53.51	$12,056
Schedule 89-S GT 4 MW							
On-peak	$2,158	25,960	83.12	0.16%	$1,893	$72.90	$1,895
Off-peak	$959	14,949	64.15	0.07%	$841	$56.26	$842
Schedule 83-P	$19,349	277,907	69.63	1.46%	$16,970	$61.06	$16,839
Schedule 89-P 1-4 MW							
On-peak	$33,432	443,938	75.31	2.52%	$29,321	$66.05	$29,388
Off-peak	$15,929	270,865	58.81	1.20%	$13,970	$51.58	$14,002
Schedule 89-P GT 4 MW							
On-peak	$50,594	669,579	75.56	3.81%	$44,372	$66.27	$44,182
Off-peak	$27,012	457,380	59.06	2.03%	$23,690	$51.80	$23,589
Schedule 89-T							
On-peak	$32,852	441,977	74.33	2.47%	$28,812	$65.19	$28,804
Off-peak	$19,157	330,065	58.04	1.44%	$16,801	$50.90	$16,796
Schedule 91	$6,997	104,772	66.79	0.53%	$6,137	$58.57	$6,137
Schedule 92/94	$370	5,241	70.59	0.03%	$324	$61.91	$324
Schedule 93	$41	566	71.83	0.00%	$36	$63.00	$36
TOTAL	$1,328,574	18,531,583	71.69	100.00%	$1,165,195	$62.88	$1,164,024
				TARGET	$1,165,195		

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TRANSMISSION REVENUE REQUIREMENT
2009

Grouping	12 CP (kW)	Percent Contribution	Allocated Revenue Requirement
Schedule 7	1,495,283	47.70%	$14,993
Schedule 15	2,325	0.07%	$23
Schedule 32	230,592	7.36%	$2,312
Schedule 38	4,517	0.14%	$45
Schedule 47	3,908	0.12%	$39
Schedule 49	11,717	0.37%	$117
Schedule 83	926,504	29.56%	$9,290
Schedule 89 1-4 MW	215,199	6.87%	$2,158
Schedule 89 GT 4 MW	233,545	7.45%	$2,342
Schedule 91	10,325	0.33%	$104
Schedule 92/94	600	0.02%	$6
Schedule 93	85	0.00%	$1
Target	3,134,600	100.00%	$31,430

PORTLAND GENERAL ELECTRIC
ALLOCATION OF ANCILLARY SERVICE COSTS
2009

Grouping	Production Allocation Percent	Allocated Costs ($000)
Schedule 7	42.14%	$2,341
Schedule 15	0.12%	$7
Schedule 32	8.19%	$455
Schedule 38	0.36%	$20
Schedule 47	0.12%	$6
Schedule 49	0.35%	$19
Schedule 83-S	29.54%	$1,641
Schedule 89-S 1-4 MW	3.46%	$192
Schedule 89-S GT 4 MW	0.23%	$13
Schedule 83-P	1.46%	$81
Schedule 89-P 1-4 MW	3.72%	$206
Schedule 89-P GT 4 MW	5.84%	$324
Schedule 89-T	3.91%	$217
Schedule 91	0.53%	$29
Schedule 92	0.03%	$2
Schedule 93	0.00%	$0
TOTAL	100.00%	$5,555
	TARGET	$5,555

PORTLAND GENERAL ELECTRIC
STATE OF OREGON
Applicable 2009 Ancillary Services Charges

Line	Ancillary Service	Billing Determinant	OATT Price	Total
	SCHEDULE 1 - SCHEDULING, SYSTEM CONTROL and DISPATCH		$/MW year	
1	12 CP MW Average	3,360	$149.89	$503,670
	SCHEDULE 2 - REACTIVE SUPPLY & VOLTAGE CONTROL		$/kW year	
2	12 CP kW Average	3,360,267	$0.461	$1,549,083
	SCHEDULE 3 - REGULATION & FREQUENCY RESPONSE		$/kW month	
3	Billing Determinant: Sum of Monthly Average 12 CP KW	40,323,200	$0.09	$3,509,530
	Charge: $6.695 per kW per month x .013			
4		**ANCILLARY SERVICES TOTAL**		$5,562,283

PORTLAND GENERAL ELECTRIC
ALLOCATION OF TROJAN DECOMMISSIONING COSTS
2009

Grouping	Cycle Energy (MWh)	Line Losses	Busbar Energy	Allocation Percent	Costs ($000)
Schedule 7	7,712,700	8.34%	8,355,939	38.38%	$1,781
Schedule 15	24,086	8.34%	26,095	0.12%	$6
Schedule 32	1,500,066	8.34%	1,625,171	7.46%	$346
Schedule 38	65,998	8.34%	71,502	0.33%	$15
Schedule 47	21,962	8.34%	23,794	0.11%	$5
Schedule 49	66,713	8.34%	72,276	0.33%	$15
Schedule 83-S	5,481,948	8.34%	5,939,142	27.28%	$1,266
Schedule 89-S 1-4 MW	676,491	8.34%	732,911	3.37%	$156
Schedule 89-S GT 4 MW	40,953	8.34%	44,368	0.20%	$9
Schedule 83-P	275,761	4.88%	289,218	1.33%	$62
Schedule 89-P 1-4 MW	768,781	4.88%	806,298	3.70%	$172
Schedule 89-P GT 4 MW	2,214,831	4.88%	2,322,914	10.67%	$495
Schedule 89-T	1,299,267	3.37%	1,343,053	6.17%	$286
Schedule 91	104,772	8.34%	113,510	0.52%	$24
Schedule 92	5,241	8.34%	5,678	0.03%	$1
Schedule 93	566	8.34%	614	0.00%	$0
TOTAL	20,260,137		21,772,484		$4,640
				TARGET	$4,640

PORTLAND GENERAL ELECTRIC
ALLOCATION OF FRANCHISE FEES
2009

Grouping	2008 Revenues	Allocation Percent	Costs ($000)
Schedule 7	$762,320	44.79%	$19,483
Schedule 15	$4,380	0.26%	$112
Schedule 32	$141,200	8.30%	$3,609
Schedule 38	$6,281	0.37%	$161
Schedule 47	$2,221	0.13%	$57
Schedule 49	$4,816	0.28%	$123
Schedule 83-S	$421,457	24.76%	$10,772
Schedule 89-S 1-4 MW	$48,870	2.87%	$1,249
Schedule 89-S GT 4 MW	$2,947	0.17%	$75
Schedule 83-P	$19,605	1.15%	$501
Schedule 89-P 1-4 MW	$51,883	3.05%	$1,326
Schedule 89-P GT 4 MW	$140,527	8.26%	$3,592
Schedule 89-T	$78,191	4.59%	$1,998
Schedule 91	$16,916	0.99%	$432
Schedule 92 & 94	$381	0.02%	$10
Schedule 93	$86	0.01%	$2
TOTAL	$1,702,081	100.00%	$43,502
		TARGET	$43,502

Note: DA customers priced at COS for allocation

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2009

Grouping	Cycle Energy	Percent	Allocations ($000)
Schedule 83-S	5,481,948	51.1%	10,274
Schedule 89-S 1-4 MW	676,491	6.3%	1,268
Schedule 89-S GT 4 MW	40,953	0.4%	77
Schedule 83-P	275,761	2.6%	517
Schedule 89-P 1-4 MW	768,781	7.2%	1,441
Schedule 89-P GT 4 MW	2,214,831	20.6%	4,151
Schedule 89-T	1,274,153	11.9%	2,388
TOTAL	10,732,918	100.00%	20,115
		TARGET	20,115

Note: cycle energy includes direct access customers

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2009

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 7 Residential							
CUSTOMER	Meters						
		Single-Phase Customers	715,997	Customers	$11.76	$8,420	$7,874
		Three-Phase Customers	472	Customers	$45.83	$22	$20
FACILITIES	13 kV						
		Single-Phase Customers	2,168,154	kW, rateclass peak	$31.03	$67,278	$62,915
		Three-Phase Customers	1,429	kW, rateclass peak	$22.02	$31	$29
	Connect Costs						
		Single-Phase Customers	715,997	Customers	$136.38	$97,648	$91,316
		Three-Phase Customers	472	Customers	$206.82	$98	$91
DEMAND	Subtransmission		2,169,583	kW, rateclass peak	$11.49	$24,929	$23,312
	Substation		2,169,583	kW, rateclass peak	$17.15	$37,208	$34,796
SUBTOTAL						$235,633	$220,354
Schedule 15 Residential Outdoor Area Lighting							
CUSTOMER	Customer Service		9,773	Lights	$4.68	$46	$43
FACILITIES	13 kV		1,874	kW, rateclass peak	$31.03	$58	$54
	Connect Costs (transformer only)		9,773	Lights	$2.27	$22	$21
DEMAND	Subtransmission		1,874	kW, rateclass peak	$11.49	$22	$20
	Substation		1,874	kW, rateclass peak	$17.15	$32	$30
FIXED	Luminaires & Poles						$661
SUBTOTAL						$180	$829
Schedule 15 Commercial Outdoor Area Lighting							
CUSTOMER	Customer Service		11,536	Lights	$4.68	$54	$50
FACILITIES	13 kV		4,491	kW, rateclass peak	$31.03	$139	$130
	Connect Costs (transformer only)		11,536	Lights	$2.27	$26	$24
DEMAND	Subtransmission		4,491	kW, rateclass peak	$11.49	$52	$48
	Substation		4,491	kW, rateclass peak	$17.15	$77	$72
FIXED	Luminaires & Poles						$1,584
SUBTOTAL						$348	$1,909
Schedule 15 Outdoor Area Lighting							
CUSTOMER	Customer Service						$93
FACILITIES	13 kV						$185
	Connect Costs (transformer only)						$45
DEMAND	Subtransmission						$68
	Substation						$102
FIXED	Luminaires & Poles						$2,244
SUBTOTAL							$2,738

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2009

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 32 Small Non-residential General Service							
CUSTOMER	Meters						
		Single-Phase Customers	52,679	Customers	$13.20	$695	$650
		Three-Phase Customers	30,977	Customers	$59.29	$1,837	$1,718
FACILITIES	13 kV						
		Single-Phase Customers	167,808	kW, rateclass peak	$31.03	$5,207	$4,869
		Three-Phase Customers	223,680	kW, rateclass peak	$22.02	$4,925	$4,606
	Connect Costs						
		Single-Phase Customers	52,679	Customers	$167.53	$8,825	$8,253
		Three-Phase Customers	30,977	Customers	$311.70	$9,656	$9,030
DEMAND	Subtransmission		391,488	kW, rateclass peak	$11.49	$4,498	$4,207
	Substation		391,488	kW, rateclass peak	$17.15	$6,714	$6,279
SUBTOTAL						$42,358	$39,611
Schedule 38 General Service							
CUSTOMER	Meters						
		Single-Phase Customers	61	Customers	$78.23	$5	$4
		Three-Phase Customers	524	Customers	$127.09	$67	$62
FACILITIES	13 kV						
		Single-Phase Customers	1,880	kW, rateclass peak	$31.03	$58	$55
		Three-Phase Customers	38,856	kW, rateclass peak	$22.02	$856	$800
	Connect Costs						
		Single-Phase Customers	61	Customers	$357.77	$22	$20
		Three-Phase Customers	524	Customers	$857.68	$450	$421
DEMAND	Subtransmission		40,736	kW, rateclass peak	$11.49	$468	$438
	Substation		40,736	kW, rateclass peak	$17.15	$699	$653
SUBTOTAL						$2,624	$2,453
Schedule 47 Irrigation & Drainage Service - < 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	206	Customers	$45.36	$9	$9
		Three-Phase Customers	2,961	Customers	$47.34	$140	$131
FACILITIES	13 kV						
		Single-Phase Customers	105	kW, rateclass peak	$31.03	$3	$3
		Three-Phase Customers	16,409	kW, rateclass peak	$22.02	$361	$338
	Connect Costs						
		Single-Phase Customers	206	Customers	$63.53	$13	$12
		Three-Phase Customers	2,961	Customers	$113.67	$337	$315
DEMAND	Subtransmission		16,514	kW, rateclass peak	$11.49	$190	$177
	Substation		16,514	kW, rateclass peak	$17.15	$283	$265
SUBTOTAL						$1,337	$1,250

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2009

Grouping			Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 49 Irrigation & Drainage Service - > 30 kW							
CUSTOMER	Meters						
		Single-Phase Customers	8	Customers	$45.36	$0	$0
		Three-Phase Customers	1,325	Customers	$166.81	$221	$207
FACILITIES	13 kV						
		Single-Phase Customers	151	kW, rateclass peak	$31.03	$5	$4
		Three-Phase Customers	49,346	kW, rateclass peak	$22.02	$1,087	$1,016
	Connect Costs						
		Single-Phase Customers	8	Customers	$182.12	$1	$1
		Three-Phase Customers	1,325	Customers	$359.31	$476	$445
DEMAND	Subtransmission		49,497	kW, rateclass peak	$11.49	$569	$532
	Substation		49,497	kW, rateclass peak	$17.15	$849	$794
SUBTOTAL						$3,208	$3,000
Schedule 83 General Service (31-1,000 kW)							
CUSTOMER	Meters						
		Single-Phase Customers	801	Customers	$87.85	$70	$66
		Three-Phase Customers	11,808	Customers	$128.47	$1,517	$1,419
		Primary Customers	143	Customers	$1,117.95	$159	$149
FACILITIES	13 kV						
		Single-Phase Customers	23,283	kW, rateclass peak	$31.03	$722	$676
		Three-Phase Customers	1,197,922	kW, rateclass peak	$22.02	$26,378	$24,668
	Secondary Connect Costs						
		Single-Phase Customers	801	Customers	$461.49	$370	$346
		Three-Phase Customers	11,808	Customers	$1,224.35	$14,457	$13,520
	Primary Conect Costs		143	Customers	$958.67	$137	$128
DEMAND	Subtransmission		1,221,205	kW, rateclass peak	$11.49	$14,032	$13,122
	Substation		1,221,205	kW, rateclass peak	$17.15	$20,944	$19,586
SUBTOTAL						$78,787	$73,678
Schedule 89 General Service (1,001-4,000 kW)							
CUSTOMER	Secondary Meters		104	Customers	$181.72	$19	$18
	Primary Meters		85	Customers	$1,117.95	$95	$89
FACILITIES	13 kV		259,535	kW, rateclass peak	$22.02	$5,715	$5,344
	Secondary Connect Costs		104	Customers	$6,591.78	$688	$643
	Primary Connect Costs		85	Customers	$958.67	$82	$76
DEMAND	Subtransmission		259,535	kW, rateclass peak	$11.49	$2,982	$2,789
	Substation		259,535	kW, rateclass peak	$17.15	$4,451	$4,162
SUBTOTAL						$14,032	$13,122

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2009

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Schedule 89 General Service (4,000 plus kW)						
CUSTOMER	Secondary Meters	2	Customers	$181.72	$0	$0
	Primary Meters	30	Customers	$1,117.95	$34	$31
	Substation Meters	10	Customers	$24,784.56	$248	$232
FACILITIES	13 kV (Sec. & Prim. Only)	32	Customers	$46,883.00	$1,500	$1,403
	Secondary Connect Costs	2	Customers	$33,743.42	$67	$63
	Primary Connect Costs	30	Customers	$3,806.65	$114	$107
	Subtransmission Connect Costs	10	Customers	$74,729.85	$747	$699
DEMAND	Subtransmission	510,127	kW, rateclass peak	$11.49	$5,861	$5,481
	Substation (Sec. & Prim. Only)	326,134	kW, rateclass peak	$17.15	$5,593	$5,231
SUBTOTAL					$14,166	$13,247
Schedule 91 Streetlighting & Highway Lighting						
CUSTOMER	Customer Service	149,427	Lights	$4.68	$699	$653
FACILITIES	13 kV	27,685	kW, rateclass peak	$31.03	$859	$803
	Connect Costs (transformer only)	149,427	Lights	$1.40	$209	$196
DEMAND	Subtransmission	27,685	kW, rateclass peak	$11.49	$318	$297
	Substation	27,685	kW, rateclass peak	$17.15	$475	$444
FIXED	Luminaires & Poles					**$7,501**
SUBTOTAL					$2,560	$9,895
Schedules 92 & 94 Traffic Signals & Communications Devices						
FACILITIES	13 kV	649	kW, rateclass peak	$22.02	$14	$13
	Connect Costs	1,616	Intersections	$22.15	$36	$33
DEMAND	Subtransmission	649	kW, rateclass peak	$11.49	$7	$7
	Substation	649	kW, rateclass peak	$17.15	$11	$10
SUBTOTAL					$69	$64
Schedule 93 Stadium Lighting						
CUSTOMER	Meters	26	Customers	$1,678.67	$44	$41
FACILITIES	13 kV	243	kW, rateclass peak	$22.02	$5	$5
	Connect Costs	26	Customers	$155.95	$4	$4
DEMAND	Subtransmission	243	kW, rateclass peak	$11.49	$3	$3
	Substation	243	kW, rateclass peak	$17.15	$4	$4
SUBTOTAL					$60	$56

PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION COST
2009

Grouping		Usages	Units & Basis	Marginal Unit Cost	Marginal Cost Revenues	Class Revenue Requirement
Summary						
CUSTOMER	Meters	818,220	Customers		$13,602	$12,720
	Customer Service	170,736	Lights		$798	$747
FACILITIES	13 kV	4,183,500	kW, rateclass peak		$115,204	$107,733
	Connect Costs	818,220	Customers		$134,484	$125,764
DEMAND	Subtransmission	4,693,627	kW, rateclass peak		$53,930	$50,433
	Substation	4,509,634	kW rateclass Peak		$77,340	$72,325
FIXED	Luminaires & Poles					$9,745
TOTALS					$395,359	$379,467
					TARGET	$379,467
				EQUAL PERCENT		93.5%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF METERING REVENUE REQUIREMENT
2009

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Equal Percent Revenue Requirement
Schedule 7				
Single Phase	715,997	$9.95	$7,124	$16,121
Three Phase	472	$9.95	$5	$11
Schedule 15				
Residential	529	$0.00	$0	$0
Commercial	822	$0.00	$0	$0
Schedule 32				
Single Phase	52,679	$9.95	$524	$1,186
Three Phase	30,977	$9.95	$308	$697
Schedule 38				
Single Phase	61	$9.95	$1	$1
Three Phase	524	$9.95	$5	$12
Schedule 47				
Single Phase	206	$9.95	$2	$5
Three Phase	2,961	$9.95	$29	$67
Schedule 49				
Single Phase	8	$9.95	$0	$0
Three Phase	1,325	$9.95	$13	$30
Schedule 83				
Single Phase	801	$9.95	$8	$18
Three Phase	11,808	$9.95	$117	$266
Primary	143	$9.95	$1	$3
Schedule 89 1-4 MW				
Secondary	104	$9.95	$1	$2
Primary	85	$9.95	$1	$2
Schedule 89 GT 4 MW				
Secondary	2	$9.95	$0	$0
Primary	30	$9.95	$0	$1
Subtransmission	10	$9.95	$0	$0
Schedule 91	206	$0.00	$0	$0
Schedule 92/94	18	$0.00	$0	$0
Schedule 93	26	$9.95	$0	$1
TOTAL	819,795		$8,141	$18,422
			TARGET	$18,422
		EQUAL PERCENT		226%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF BILLING REVENUE REQUIREMENT
2009

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Equal Percent Revenue Requirement
Schedule 7				
Single Phase	715,997	$18.51	$13,253	$27,945
Three Phase	472	$18.51	$9	$18
Schedule 15				
Residential	529	$18.67	$10	$21
Commercial	822	$18.28	$15	$32
Schedule 32				
Single Phase	52,679	$18.27	$962	$2,029
Three Phase	30,977	$18.27	$566	$1,193
Schedule 38				
Single Phase	61	$18.42	$1	$2
Three Phase	524	$18.42	$10	$20
Schedule 47				
Single Phase	206	$18.26	$4	$8
Three Phase	2,961	$18.26	$54	$114
Schedule 49				
Single Phase	8	$18.32	$0	$0
Three Phase	1,325	$18.32	$24	$51
Schedule 83				
Single Phase	801	$18.95	$15	$32
Three Phase	11,808	$18.95	$224	$472
Primary	143	$18.95	$3	$6
Schedule 89 1-4 MW				
Secondary	104	$30.13	$3	$7
Primary	85	$30.13	$3	$5
Schedule 89 GT 4 MW				
Secondary	2	$150.91	$0	$1
Primary	30	$150.91	$5	$10
Subtransmission	10	$150.91	$2	$3
Schedule 91	206	$220.10	$45	$96
Schedule 92/94	18	$219.77	$4	$8
Schedule 93	26	$18.28	$0	$1
TOTAL	819,795		$15,212	$32,075
			TARGET	$32,075
		EQUAL PERCENT		211%

PORTLAND GENERAL ELECTRIC
ALLOCATION OF CONSUMER REVENUE REQUIREMENT
2009

Grouping	Customers	Marginal Unit Cost $ per Customer	Marginal Cost Revenues	Equal Percent Revenue Requirement
Schedule 7				
Single Phase	715,997	$38.84	$27,809	$42,436
Three Phase	472	$38.84	$18	$28
Schedule 15				
Residential	529	$38.84	$21	$31
Commercial	822	$43.57	$36	$55
Schedule 32				
Single Phase	52,679	$43.57	$2,295	$3,502
Three Phase	30,977	$43.57	$1,350	$2,060
Schedule 38				
Single Phase	61	$97.48	$6	$9
Three Phase	524	$97.48	$51	$78
Schedule 47				
Single Phase	206	$43.57	$9	$14
Three Phase	2,961	$43.57	$129	$197
Schedule 49				
Single Phase	8	$43.57	$0	$1
Three Phase	1,325	$43.57	$58	$88
Schedule 83				
Single Phase	801	$170.78	$137	$209
Three Phase	11,808	$170.78	$2,017	$3,077
Primary	143	$170.78	$24	$37
Schedule 89 1-4 MW				
Secondary	104	$1,061.45	$111	$169
Primary	85	$1,061.45	$90	$138
Schedule 89 GT 4 MW				
Secondary	2	$1,061.45	$2	$3
Primary	30	$1,061.45	$32	$49
Subtransmission	10	$1,061.45	$11	$16
Schedule 91	206	$1,061.45	$219	$334
Schedule 92/94	18	$1,061.45	$19	$29
Schedule 93	26	$43.57	$1	$2
TOTAL	819,795		$34,444	$52,561
			TARGET	$52,561
		EQUAL PERCENT		153%

TABLE 1
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
GROWTH AND RELIABILITY-RELATED SUBTRANSMISSION
INVESTMENTS ON A PER UNIT BASIS
2009 DOLLARS

LINE NO.	YEAR	NOMINAL SUBTRANS INVESTMENT	INDEX	ANNUAL SUBTRANS INVESTMENT 2009 $
		(A)	(B)	(C)
1	2005	$3,514,911	80.5%	$4,365,097
2	2006	$4,962,254	89.4%	$5,548,881
3	2007	$8,944,950	96.8%	$9,239,011
4	2008	$3,699,233	98.4%	$3,758,947
5	2009	$8,329,354	100.0%	$8,329,354

LINE NO.	TOTAL FIVE-YEAR INVESTMENTS	ECONOMIC CARRYING CHARGE	ANNUAL INCREMENTAL CAPITAL COST DOLLARS	DIVIDE BY GROWTH IN SYSTEM PEAK (1)	DEMAND-RELATED ANNUAL INCREMENTAL CAPITAL COST	
	(D)	(E)	(F) (D)*(E)	(G)	(H) (F)/(G)/1000	
6	$31,241,289	0.1107	$3,458,411	374	$9.26	PER KW

(1) PEAK IS NCP IN MW.

TABLE 2
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
GROWTH-RELATED SUBSTATION
INVESTMENTS ON A PER UNIT BASIS
2009 DOLLARS

LINE NO.	YEAR	NOMINAL SUBSTATION INVESTMENT	INDEX	ANNUAL SUBTRANS SUBSTATION 2009 $
		(A)	(B)	(C)
1	2005	$12,829,594	80.5%	$15,932,812
2	2006	$8,968,803	89.4%	$10,029,076
3	2007	$4,671,865	96.8%	$4,825,450
4	2008	$8,491,870	98.4%	$8,628,947
5	2009	$13,773,381	100.0%	$13,773,381

LINE NO.	TOTAL FIVE-YEAR INVESTMENTS	ECONOMIC CARRYING CHARGE	ANNUAL INCREMENTAL CAPITAL COST DOLLARS	DIVIDE BY GROWTH IN SYSTEM PEAK (1)	DEMAND-RELATED ANNUAL INCREMENTAL CAPITAL COST	
	(D)	(E)	(F) (D)*(E)	(G)	(H) (F)/(G)/1000	
6	$53,189,667	0.1051	$5,590,234	356	$15.69	PER KW

(1) PEAK IS NCP IN MW FOR CUSTOMERS AT PRIMARY AND SECONDARY DELIVERY VOLTAGE.

TABLE 3
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
MARGINAL COST OF DISTRIBUTION FEEDERS

FEEDER NAME	Shared Wire Costs	Three phase Tapline Costs	Single phase Tapline Costs	Feeder Demand	Three phase Demand	Single phase Demand	Shared Cost $/kW	Three phase Taplines $/kW	Single phase Taplines $/kW	3-phase $/kW	Single phase $/kW	Annualized 3-phase $/kW	Annualized Single phase $/kW
1 BELL-FLAVEL	$422,662	$60,299	$350,096	11,643	4,359	7,284	$36.30	$13.83	$48.06	$50.13	$84.36	$5.58	$9.40
2 BOONS-WMBLY PK	$728,660	$9,300	$254,085	4,155	1,132	3,023	$175.37	$8.21	$84.05	$183.58	$259.42	$20.45	$28.90
3 MULTNOMAH 13KV	$745,939	$12,092	$620,679	9,892	1,043	8,849	$75.41	$11.60	$70.14	$87.01	$145.55	$9.69	$16.21
4 SELLWD-WAVERLY	$447,420	$106,248	$92,851	5,964	2,932	3,032	$75.02	$36.23	$30.62	$111.25	$105.64	$12.39	$11.77
5 CLAXTAR-HAYSVIL	$480,077	$57,854	$198,986	8,880	3,184	5,696	$54.06	$18.17	$34.93	$72.24	$89.00	$8.05	$9.91
6 KING CTY-HAZEL	$1,224,786	$231,790	$214,842	14,261	9,327	4,934	$85.88	$24.85	$43.54	$110.74	$129.43	$12.34	$14.42
7 ORENCO 13KV	$1,735,825	$71,342	$84,737	11,370	6,104	5,266	$152.67	$11.69	$16.09	$164.35	$168.76	$18.31	$18.80
8 TIGARD-13336	$389,030	$63,278	$71,620	8,690	5,894	2,796	$44.77	$10.74	$25.61	$55.50	$70.38	$6.18	$7.84
9 GLNDOVEER-13597	$429,507	$31,714	$190,502	6,299	2,458	3,841	$68.18	$12.90	$49.59	$81.08	$117.78	$9.03	$13.12
10 FAIRMT-MISSION	$1,981,405	$178,124	$1,022,033	8,788	2,903	5,885	$225.46	$61.36	$173.66	$286.82	$399.13	$31.95	$44.46
11 INDIAN-LABISH	$2,366,297	$498,804	$456,369	9,413	4,020	5,393	$251.39	$124.08	$84.63	$375.47	$336.02	$41.83	$37.43
12 MERIDIAN 13KV	$1,762,334	$43,531	$1,689,025	9,674	2,021	7,653	$182.17	$21.54	$220.70	$203.71	$402.88	$22.69	$44.88
13 WELCHES-ZIG ZAG	$2,059,983	$30,230	$1,216,202	5,255	1,059	4,195	$392.03	$28.53	$289.90	$420.57	$681.94	$46.85	$75.97
TOTALS	$14,773,924	$1,394,606	$6,462,028	114,284	46,437	67,847	$129.27	$30.03	$95.24	$159.31	$224.52	$17.75	$25.01

Carrying Charge 11.14%

DISTRIBUTION FEEDER COST PER CUSTOMER OF 4 MW CUSTOMERS

Distance from Substation 1000'	Feeder Cost per 1000'	Cost per Customer	Carrying Charge	Annualized Cost
6.0	$56,721	$339,193	11.14%	$37,786

Note: Distance includes redundant feeder for maintenance and reliability

TABLE 4
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
SUMMARY OF CONNECT COSTS

Grouping	Loaded Connect Costs (2007 Dollars) (1)	Inflation Rate (2)	Loaded Connect Costs (2009 Dollars)	Carrying Charge	Annualized Connect Costs
Schedule 7					
Single phase	$966.62	103.3%	$998.40	11.01%	$109.92
Three phase	LEA		$1,514.00	11.01%	$166.69
Schedule 15	$16.06	103.3%	$16.59	11.01%	$1.83
Schedule 32					
Single phase	$1,187.32	103.3%	$1,226.36	11.01%	$135.02
Three phase	$2,209.15	103.3%	$2,281.78	11.01%	$251.22
Schedule 38					
Single phase	LEA	103.3%	$2,619.00	11.01%	$288.35
Three phase	LEA	103.3%	$6,278.52	11.01%	$691.26
Schedule 47					
Single phase	LEA		$465.04	11.01%	$51.20
Three phase	LEA		$832.07	11.01%	$91.61
Schedule 49					
Single phase	LEA		$1,333.16	11.01%	$146.78
Three phase	LEA		$2,630.27	11.01%	$289.59
Schedule 83					
Single phase	$3,270.67	103.3%	$3,378.19	11.01%	$371.94
Three phase	$8,677.27	103.3%	$8,962.54	11.01%	$986.78
Schedule 89 1-4 MW	$46,717.81	103.3%	$48,253.63	11.01%	$5,312.73
Schedule 89 GT 4 MW	$239,149.49	103.3%	$247,011.41	11.01%	$27,195.96
Primary Voltage					
Schedule 83	$6,794.36	103.3%	$7,017.72	11.01%	$772.65
Schedule 89 1-4 MW	$6,794.36	103.3%	$7,017.72	11.01%	$772.65
Schedule 89 GT 4 MW	$26,978.81	103.3%	$27,865.72	11.01%	$3,068.02
Subtrans. Voltage	$529,632	103.3%	$547,043.70	11.01%	$60,229.51
Schedule 91	$9.96	103.3%	$10.29	11.01%	$1.13
Schedule 92	LEA		$162.16	11.01%	$17.85
Schedule 93	LEA		$1,141.57	11.01%	$125.69

Notes:
(1) From Job Estimate Sheets Service & Design Consultants
(2) GNP implicit price deflator 2007 to 2009
(3) Schedule 91 figure is for shared transformer only

TABLE 5
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
CAPITAL COST OF INSTALLED METERS

Customer Schedule	Meter Type	Installed Cost (2009 $)	Customer Weighting	Weighted Average Meter Cost (2009 $)	Annual Carrying Charge	Annualized Cost
Residential						
Single phase	Form 2S, 200 amp, 240 volt	$51.34	100.00%	$51.34	19.74%	$10.14
Three phase	200 amp, self contained meter	$200.15	100.00%	$200.15	19.74%	$39.51
Schedule 32						
Single phase	Form 2S, 200 amp, 240 volt	$51.34	92.92%			
Single phase	Form 2S, 320 amp, 240 volt	$102.03	4.23%			
Single phase	Form 2S, 320 amp, 240 volt, kwh, kw	$198.08	2.85%	$57.67	19.74%	$11.38
Three phase	200 amp, self contained meter	$200.15	81.80%			
Three phase	Transformer Rated Meter	$522.92	18.20%	$258.90	19.74%	$51.11
Schedule 38						
Single phase	Self-contained Meter	$155.74	18.42%			
Single phase	Transformer Rated Meter	$383.63	81.58%	$341.65	19.74%	$67.44
Three phase	Self-contained Meter	$200.15	0.46%			
Three phase	Transformer Rated Meter	$522.93	85.25%			
Three phase	kWH & kW & kVAR	$755.33	13.36%			
Three phase	kWH & kW & kVAR	$793.55	0.92%	$555.00	19.74%	$109.56
Schedule 47						
Single phase	Form 2S, 320 amp, 240 volt, kwh, kw	$198.08	100.00%	$198.08	19.74%	$39.10
Three phase	200 amp, self contained meter	$200.15	97.96%			
Three phase	Transformer Rated Meter	$522.92	2.04%	$206.75	19.74%	$40.81
Schedule 49						
Single phase	Form 2S, 320 amp, 240 volt, kwh, kw	$198.08	100.00%			
Single phase	Transformer Rated Meter	$383.63	0.00%	$198.08	19.74%	$39.10
Three phase	Self-contained Meter	$200.15	4.84%			
Three phase	Transformer Rated Meter	$522.93	0.00%			
Three phase	kWH & kW & kVAR	$755.33	95.16%	$728.45	19.74%	$143.80
Schedule 83	**Secondary Voltage**					
Single phase	Transformer Rated Meter	$383.63	100.00%	$383.63	19.74%	$75.73
Three phase	Transformer Rated Meter	$522.93	83.61%			
Three phase	kWH & kW & kVAR	$755.33	16.39%	$561.02	19.74%	$110.75
Schedule 89 1-4 MW						
Three phase	kWH & kW & kVAR	$793.55	100.00%	$793.55	19.74%	$156.65
Schedule 89 GT 4 MW						
Three phase	kWH & kW & kVAR	$793.55	100.00%	$793.55	19.74%	$156.65
Primary Voltage						
Schedule 83	kWH & kW & kVAR	$4,882.07	100.00%	$4,882.07	19.74%	$963.72
Schedule 89 1-4 MW	kWH & kW & kVAR	$4,882.07	100.00%	$4,882.07	19.74%	$963.72
Schedule 89 GT 4 MW	kWH & kW & kVAR	$4,882.07	100.00%	$4,882.07	19.74%	$963.72
Subtrans. Voltage	kWH & kW & kVAR	$108,233.59	100.00%	$108,233.59	19.74%	$21,365.31
Schedule 93						
Three phase	kWH & kW & kVAR	$7,330.68	100.00%	$7,330.68	19.74%	$1,447.08

TABLE 6
PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION O&M

Allocation of Substation O&M

Schedule	Marginal Capital Cost $/kW	Usages	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost $/kW
Schedule 7	$15.69	2,169,583	$34,040,757	$3,156,805	$17.15
Schedule 15	$15.69	6,365	$99,867	$9,261	$17.15
Schedule 32	$15.69	391,488	$6,142,447	$569,626	$17.15
Schedule 38	$15.69	40,736	$639,148	$59,272	$17.15
Schedule 47	$15.69	16,514	$259,105	$24,028	$17.15
Schedule 49	$15.69	49,497	$776,608	$72,020	$17.15
Schedule 83	$15.69	1,221,205	$19,160,706	$1,776,888	$17.15
Schedule 89 1-4 MW	$15.69	259,535	$4,072,104	$377,631	$17.15
Schedule 89 GT 4 MW	$15.69	326,134	$5,117,042	$474,534	$17.15
Schedule 91	$15.69	27,685	$434,378	$40,282	$17.15
Schedules 92 & 94	$15.69	649	$10,183	$944	$17.15
Schedule 93	$15.69	243	$3,813	$354	$17.15
Totals		4,509,634	$70,756,157	$6,561,646	
FERC Accounts 582 & 592 Test Period O&M			$6,561,646		

Allocation of Meters O&M

Schedule	Marginal Capital Cost	Average Customers	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$10.14	715,997	$7,260,205	$1,161,903	$11.76
Three-phase	$39.51	472	$18,642	$2,983	$45.83
Schedule 15		1,351			
Schedule 32					
Single-phase	$11.38	52,679	$599,488	$95,940	$13.20
Three-phase	$51.11	30,977	$1,583,256	$253,380	$59.29
Schedule 38					
Single-phase	$67.44	61	$4,103	$657	$78.23
Three-phase	$109.56	524	$57,455	$9,195	$127.09
Schedule 47					
Single-phase	$39.10	206	$8,055	$1,289	$45.36
Three-phase	$40.81	2,961	$120,838	$19,339	$47.34
Schedule 49					
Single-phase	$39.10	8	$313	$50	$45.36
Three-phase	$143.80	1,325	$190,535	$30,493	$166.81
Schedule 83 S					
Single-phase	$75.73	801	$60,679	$9,711	$87.85
Three-phase	$110.75	11,808	$1,307,736	$209,287	$128.47
Schedule 89 S 1-4 MW	$156.65	104	$16,344	$2,616	$181.72
Schedule 83 S GT 4 MW	$156.65	2	$313	$50	$181.72
Schedule 83 P	$963.72	143	$137,491	$22,004	$1,117.95
Schedule 89 P 1-4 MW	$963.72	85	$82,077	$13,135	$1,117.95
Schedule 83 P GT 4 MW	$963.72	30	$28,912	$4,627	$1,117.95
Schedule 89 T	$21,365.31	10	$213,653	$34,192	$24,784.56
Schedule 91		206			
Schedule 92/94		18			
Schedule 93	$1,447.08	26	$37,624	$6,021	$1,678.67
Totals		819,795	$11,727,717	$1,876,872	
FERC Accounts 586 & 597 Test Period O&M			$1,876,872		

TABLE 6
PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION O&M

Allocation of Connect Costs O&M

Schedule	Marginal Capital Costs	Average Customers	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$109.92	715,997	$78,702,335	$18,947,696	$136.38
Three-phase	$166.69	472	$78,650	$18,935	$206.82
Schedule 15	$1.83	1,351	$2,472	$595	$2.27
Schedule 32					
Single-phase	$135.02	52,679	$7,112,730	$1,712,400	$167.53
Three-phase	$251.22	30,977	$7,782,147	$1,873,563	$311.70
Schedule 38					
Single-phase	$288.35	61	$17,541	$4,223	$357.77
Three-phase	$691.26	524	$362,508	$87,274	$857.68
Schedule 47					
Single-phase	$51.20	206	$10,547	$2,539	$63.53
Three-phase	$91.61	2,961	$271,257	$65,306	$113.67
Schedule 49					
Single-phase	$146.78	8	$1,174	$283	$182.12
Three-phase	$289.59	1,325	$383,707	$92,378	$359.31
Schedule 83 S					
Single-phase	$371.94	801	$298,017	$71,748	$461.49
Three-phase	$986.78	11,808	$11,651,898	$2,805,211	$1,224.35
Schedule 89 S 1-4 MW	$5,312.73	104	$554,295	$133,447	$6,591.78
Schedule 89 S GT 4 MW	$27,195.96	2	$54,392	$13,095	$33,743.42
Schedule 83 P	$772.65	143	$110,231	$26,538	$958.67
Schedule 89 P 1-4 MW	$772.65	85	$65,804	$15,842	$958.67
Schedule 89 P GT 4 MW	$3,068.02	30	$92,041	$22,159	$3,806.65
Schedule 89 T	$60,229.51	10	$602,295	$145,003	$74,729.85
Schedule 91	$1.13	206	$233	$56	$1.40
Schedule 92	$17.85	18	$321	$77	$22.15
Schedule 93	$125.69	26	$3,268	$787	$155.95
Totals		819,795	$108,157,864	$26,039,155	
Connect Cost O&M			$26,039,155		

Allocation of 13 kV O&M

Schedule	Marginal 13 kV Cost	Usage	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost
Schedule 7					
Single-phase	$25.01	2,168,154	$54,225,532	$13,054,872	$31.03
Three-phase	$17.75	1,429	$25,365	$6,107	$22.02
Schedule 15	$25.01	6,365	$159,189	$38,325	$31.03
Schedule 32					
Single-phase	$25.01	167,808	$4,196,878	$1,010,404	$31.03
Three-phase	$17.75	223,680	$3,970,320	$955,860	$22.02
Schedule 38					
Single-phase	$25.01	1,880	$47,023	$11,321	$31.03
Three-phase	$17.75	38,856	$689,691	$166,044	$22.02
Schedule 47					
Single-phase	$25.01	105	$2,626	$632	$31.03
Three-phase	$17.75	16,409	$291,260	$70,121	$22.02
Schedule 49					
Single-phase	$25.01	151	$3,777	$909	$31.03
Three-phase	$17.75	49,346	$875,892	$210,872	$22.02
Schedule 83					
Single-phase	$25.01	23,283	$582,317	$140,194	$31.03
Three-phase	$17.75	1,197,922	$21,263,109	$5,119,123	$22.02
Schedule 89 1-4 MW	$17.75	259,535	$4,606,746	$1,109,081	$22.02
Schedule 89 GT 4 MW	$37,786	32	$1,209,152	$291,105	$46,883
Schedule 91	$25.01	27,685	$692,402	$166,697	$31.03
Schedule 92	$17.75	649	$11,520	$2,773	$22.02
Schedule 93	$17.75	243	$4,313	$1,038	$22.02
Totals			$92,857,110	$22,355,477	
13 kV O&M			$22,355,477		

TABLE 6
PORTLAND GENERAL ELECTRIC
ALLOCATION OF DISTRIBUTION O&M

Allocation of Subtransmission O&M

Schedule	Marginal Inv. Cost $/kW	Usages	Annualized Capital Cost	Allocated O&M	Marginal Unit Cost $/kW
Schedule 7	$9.26	2,169,583	$20,090,339	$4,836,777	$11.49
Schedule 15	$9.26	6,365	$58,940	$14,190	$11.49
Schedule 32	$9.26	391,488	$3,625,179	$872,767	$11.49
Schedule 38	$9.26	40,736	$377,215	$90,815	$11.49
Schedule 47	$9.26	16,514	$152,920	$36,816	$11.49
Schedule 49	$9.26	49,497	$458,342	$110,347	$11.49
Schedule 83	$9.26	1,221,205	$11,308,358	$2,722,503	$11.49
Schedule 89 1-4 MW	$9.26	259,535	$2,403,294	$578,596	$11.49
Schedule 89 GT 4 MW	$9.26	510,127	$4,723,776	$1,137,256	$11.49
Schedule 91	$9.26	27,685	$256,363	$61,720	$11.49
Schedule 92	$9.26	649	$6,010	$1,447	$11.49
Schedule 93	$9.26	243	$2,250	$542	$11.49
Totals		4,693,627	$43,462,986	$10,463,774	
Subtransmission O&M			$10,463,774		

	Capital	O&M
Connect Capital	$108,157,864	$26,039,155
13 kV Capital	$92,857,110	$22,355,477
Subtransmission Capital	$43,462,986	$10,463,774
	$244,477,960	$58,858,406

FERC Accounts 583, 584, 593, 594, 595 Test Period O&M $58,858,406

FERC Account	O&M	Allocated	Total	Category
582 & 592	$4,127,368	$2,434,278	$6,561,646	Substations
586 & 597	$1,180,579	$696,293	$1,876,872	Meters
583, 584, 593-595	$37,022,769	$21,835,637	$58,858,406	OH, UG, connect
Subtotal	$42,330,716	$24,966,208	$67,296,924	

FERC Account	O&M	Category
580, 587, 588, 589, 590, 591, 598	$24,966,208	Supervision & Misc.

TABLE 7
PORTLAND GENERAL ELECTRIC
MARGINAL COST STUDY
SUMMARY OF CONSUMER SERVICE MARGINAL COSTS

SCHEDULE	ANNUAL METER READING EXPENSES	ANNUAL BILLING EXPENSES	ANNUAL OTHER CONSUMER EXPENSES	TOTAL CONSUMER EXPENSES
Schedule 7 Residential	$9.95	$18.51	$38.84	$67.30
Schedule 15 Residential	$0.00	$18.67	$38.84	$57.51
Schedule 15 Commercial	$0.00	$18.28	$43.57	$61.85
Schedule 32 General Service	$9.95	$18.27	$43.57	$71.79
Schedule 38 GS TOU LT 200 kW	$9.95	$18.42	$97.48	$125.86
Schedule 47 Irrigation	$9.95	$18.26	$43.57	$71.78
Schedule 49 Irrigation	$9.95	$18.32	$43.57	$71.84
Schedule 83 General Service	$9.95	$18.95	$170.78	$199.69
Schedule 89 1-4 MW	$9.95	$30.13	$1,061.45	$1,101.53
Schedule 89 GT 4 MW	$9.95	$150.91	$1,061.45	$1,222.31
Schedule 91 Streetlighting	$0.00	$220.10	$1,061.45	$1,281.55
Schedule 92 / 94 Traffic Sign. & Comm. Dev.	$0.00	$219.77	$1,061.45	$1,281.21
Schedule 93 Field Lighting	$9.95	$18.28	$43.57	$71.80

TABLE 8
PORTLAND GENERAL ELECTRIC
SUMMARY OF MARGINAL COST STUDY

SCHEDULE	SUBTRANSMISSION COSTS	SUBSTATION COSTS	13 KV COSTS	CONNECT COSTS	METER COSTS	END-USE CUSTOMER COSTS
Schedule 7 Residential						
Single-phase	$11.49	$17.15	$31.03	$136.38	$11.76	$67.30
Three-phase	$11.49	$17.15	$22.02	$206.82	$45.83	$67.30
Schedule 15 Residential	$11.49	$17.15	$31.03	$2.27	N/A	$57.51
Schedule 15 Commercial	$11.49	$17.15	$31.03	$2.27	N/A	$61.85
Schedule 32 General Service						
Single-phase	$11.49	$17.15	$31.03	$167.53	$13.20	$71.79
Three-phase	$11.49	$17.15	$22.02	$311.70	$59.29	$71.79
Schedule 38 TOU						
Single-phase	$11.49	$17.15	$31.03	$357.77	$78.23	$125.85
Three-phase	$11.49	$17.15	$22.02	$857.68	$127.09	$125.85
Schedule 47 Irrigation						
Single-phase	$11.49	$17.15	$31.03	$63.53	$45.36	$71.78
Three-phase	$11.49	$17.15	$22.02	$113.67	$47.34	$71.78
Schedule 49 Irrigation						
Single-phase	$11.49	$17.15	$31.03	$182.12	$45.36	$71.84
Three-phase	$11.49	$17.15	$22.02	$359.31	$166.81	$71.84
Schedule 83 Secondary General Service						
Single-phase	$11.49	$17.15	$31.03	$461.49	$87.85	$199.68
Three-phase	$11.49	$17.15	$22.02	$1,224.35	$128.47	$199.68
Schedule 83 Primary General Service	$11.49	$17.15	$22.02	$958.67	$1,117.95	$199.68
Schedule 89 Secondary 1-4 MW	$11.49	$17.15	$22.02	$6,591.78	$181.72	$1,101.53
Schedule 89 Primary 1-4 MW	$11.49	$17.15	$22.02	$958.67	$1,117.95	$1,101.53
Schedule 89 Secondary GT 4 MW	$11.49	$17.15	$46,883	$33,743.42	$181.72	$1,222.31
Schedule 89 Primary GT 4 MW	$11.49	$17.15	$46,883	$3,806.65	$1,117.95	$1,222.31
Schedule 89 Subtransmission	$11.49	N/A	N/A	$74,729.85	$24,784.56	$1,222.31
Schedule 91 Streetlighting	$11.49	$17.15	$31.03	$1.40	N/A	$1,281.55
Schedules 92 & 94 Traffic Signals & Comm. Devices	$11.49	$17.15	$22.02	$22.15	N/A	$1,281.22
Schedule 93 Field Lighting	$11.49	$17.15	$22.02	$155.95	$1,678.67	$71.80

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Kuns - Cody / 1

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Revenue Summary

Schedule 91 LUMINAIRE CODE	Description of Light	Type	Watts	Category	PROPOSED PRICES Tariff Base Rates plus Energy OPTION-A	OPTION-B	OPTION-C	2009 AVERAGE COUNTS OPTION-A	OPTION-B	OPTION-C	TOTAL	2009 ESTIMATED ANNUAL STREETLIGHT REVENUES OPTION-A	OPTION-B	OPTION-C	TOTAL
84	Cobrahead - (Minimum of 2500 Power Doors)	HPS	100-watt	Standard	$ -	$ 6.62	$ 3.92	-	27,951	784	28,735	$ -	$ 2,221,314	$ 36,879	$ 2,258,194
85	Cobrahead - (Minimum of 2500 Power Doors)	HPS	150-watt	Standard	-	8.37	5.66	-	1,758	1,139	2,897	-	176,615	77,361	253,976
89	Cobrahead - (Minimum of 2500 Power Doors)	HPS	200-watt	Standard	-	9.97	7.21	-	5,054	261	5,315	-	604,572	22,582	627,153
86	Cobrahead - (Minimum of 2500 Power Doors)	HPS	250-watt	Standard	-	12.04	9.31	-	2,380	881	3,261	-	343,879	98,425	442,305
87	Cobrahead - (Minimum of 2500 Power Doors)	HPS	400-watt	Standard	-	17.62	14.88	-	1,837	65	1,902	-	388,413	11,606	400,020
34	Cobrahead - (Not applicable to PD rate)	HPS	100-watt	Standard	9.20	6.72	3.92	16,438	15,460	740	32,638	1,813,924	1,245,913	34,810	3,094,647
35	Cobrahead - (Not applicable to PD rate)	HPS	150-watt	Standard	10.96	8.47	5.66	997	6,546	864	8,407	131,178	665,682	58,683	855,544
39	Cobrahead - (Not applicable to PD rate)	HPS	200-watt	Standard	12.93	10.07	7.21	3,725	4,896	1,110	9,731	578,015	591,691	96,037	1,265,743
36	Cobrahead - (Not applicable to PD rate)	HPS	250-watt	Standard	15.08	12.18	9.31	541	2,423	916	3,880	97,901	354,155	102,336	554,391
37	Cobrahead - (Not applicable to PD rate)	HPS	400-watt	Standard	20.67	17.77	14.88	769	2,076	337	3,182	190,733	442,660	60,175	693,567
31	Flood	HPS	250-watt	Standard	15.35	12.21	9.31	89	6	2	97	16,392	879	223	17,494
32	Flood	HPS	400-watt	Standard	20.94	17.80	14.88	292	42	7	341	73,363	8,970	1,250	83,582
40	Early American Post-Top	HPS	100-watt	Standard	9.60	6.72	3.92	4,519	3,910	930	9,359	520,360	315,105	43,747	879,212
76	Shoebox	HPS	70-watt	Standard	8.64	5.62	2.74	-	-	-	-	-	-	-	-
77	Shoebox	HPS	100-watt	Standard	10.03	6.82	3.92	2,352	5,290	2,125	9,767	283,037	432,822	99,960	815,820
78	Shoebox	HPS	150-watt	Standard	12.04	8.59	5.66	243	425	266	934	35,097	43,790	18,067	96,954
								29,965	80,054	10,427	120,446	$ 3,740,002	$ 7,836,459	$ 762,141	$ 12,338,602
81	Special Acorn	HPS	100-watt	Custom	$ 12.64	$ 7.13	$ 3.92	659	3,803	530	4,992	$ 99,923	$ 325,185	$ 24,931	$ 450,039
12	Special Acorn - Independence	HPS	100-watt	Custom	11.93	7.01	3.92	-	-	-	-	-	-	-	-
13	Special Acorn - Independence	HPS	150-watt	Custom	13.68	8.76	5.66	-	-	-	-	-	-	-	-
64	Special Architectural - Capitol Acorn	HPS	100-watt	Custom	16.11	7.37	3.92	-	-	-	-	-	-	-	-
65	Special Architectural - Capitol Acorn	HPS	200-watt	Custom	19.45	10.73	7.21	-	-	-	-	-	-	-	-
66	Special Architectural - Capitol Acorn	HPS	250-watt	Custom	21.55	12.83	9.31	-	-	-	-	-	-	-	-
67	Special Architectural - Capitol Acorn	HPS	150-watt	Custom	17.89	9.17	5.66	-	-	-	-	-	-	-	-
82	Special Architectural - Victorian	HPS	150-watt	Custom	14.10	8.85	5.66	43	985	332	1,360	7,274	104,571	22,549	134,395
49	Special Architectural - Victorian	HPS	200-watt	Custom	15.70	10.41	7.21	-	119	9	128	-	14,860	779	15,639
83	Special Architectural - Victorian	HPS	250-watt	Custom	17.89	12.52	9.31	67	1,229	5	1,301	14,380	184,580	559	199,519
98	Special Architectural - Techtra	HPS	100-watt	Custom	18.75	7.85	3.92	465	83	-	548	104,313	7,743	-	112,056
99	Special Architectural - Techtra	HPS	150-watt	Custom	20.50	9.60	5.66	4	-	-	4	981	-	-	981
88	Special Architectural - Techtra	HPS	250-watt	Custom	29.78	13.31	9.31	-	132	-	132	-	22,023	-	22,023
96	Special Architectural - KIM Archetype	HPS	250-watt	Custom	-	12.65	9.31	-	55	18	73	-	8,346	2,011	10,357
97	Special Architectural - KIM Archetype	HPS	400-watt	Custom	-	18.22	14.88	-	20	28	48	-	4,372	5,000	9,372
90	Special Architectural - Westbrooke Acorn	HPS	70-watt	Custom	15.63	6.03	2.74	-	-	-	-	-	-	-	-
91	Special Architectural - Westbrooke Acorn	HPS	100-watt	Custom	16.76	7.19	3.92	-	-	-	-	-	-	-	-
92	Special Architectural - Westbrooke Acorn	HPS	150-watt	Custom	18.51	8.94	5.66	-	-	-	-	-	-	-	-
93	Special Architectural - Westbrooke Acorn	HPS	200-watt	Custom	20.20	10.49	7.21	-	-	-	-	-	-	-	-
94	Special Architectural - Westbrooke Acorn	HPS	250-watt	Custom	22.32	12.61	9.31	-	-	-	-	-	-	-	-
48	Special Types - Cobrahead	MH	175-watt	Custom	11.98	9.43	6.48	4	2	62	68	575	226	4,821	5,623
60	Special Types - Flood	MH	400-watt	Custom	20.31	17.29	14.24	15	-	-	15	3,655	-	-	3,655
47	Special Types - Flood	HPS	750-watt	Custom	34.42	30.01	26.01	26	24	-	50	10,738	8,642	-	19,380
9	Special Types - Mongoose	HPS	150-watt	Custom	13.06	8.79	5.66	-	9	-	9	-	949	-	949
10	Special Types - Mongoose	HPS	250-watt	Custom	16.80	12.45	9.31	2	-	-	2	403	-	-	403
11	Special Types - Mongoose	HPS	400-watt	Custom	22.41	18.04	14.88	-	-	-	0	-	-	-	-
2	Alternative Special Acorn - Victorian	QL	85-watt	Alternative	13.54	5.00	2.92	-	11	80	91	-	660	2,803	3,463
1	Alternative Special Acorn - Victorian	QL	165-watt	Alternative	17.80	7.65	5.48	-	104	46	150	-	9,549	3,025	12,574
4	Alternative Special Acorn - Techtra	QL	85-watt	Alternative	16.91	5.12	2.92	-	-	-	0	-	-	-	-
3	Alternative Special Acorn - Techtra	QL	165-watt	Alternative	20.20	7.74	5.48	-	151	-	151	-	14,017	-	14,017
								1,285	6,727	1,110	9,122	$ 242,244	$ 705,725	$ 66,478	$ 1,014,447

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Revenue Summary

Schedule 91 LUMINAIRE CODE	Description of Light	Type	Watts	Category		PROPOSED PRICES Tariff Base Rates plus Energy			2009 AVERAGE COUNTS				2009 ESTIMATED ANNUAL STREETLIGHT REVENUES			
						OPTION-A	OPTION-B	OPTION-C	OPTION-A	OPTION-B	OPTION-C	TOTAL	OPTION-A	OPTION-B	OPTION-C	TOTAL
19	Cobrahead - Option C Only	MV	100-watt	Obsolete	(1)	$ -	$ -	$ 3.56	-	-	1	1	$ -	$ -	$ 43	$ 43
21	Cobrahead	MV	175-watt	Obsolete	(1)	11.39	8.72	6.02	1,974	1,854	94	3,922	269,869	194,061	6,791	470,721
22	Cobrahead	MV	250-watt	Obsolete	(1)	14.90	11.53	8.58	2	-	23	25	357	-	2,368	2,726
23	Cobrahead	MV	400-watt	Obsolete	(1)	18.90	16.24	13.42	521	103	82	706	118,186	20,077	13,205	151,469
24	Cobrahead	MV	1,000-watt	Obsolete	(1)	40.41	37.26	34.13	20	16	5	41	9,699	7,154	2,048	18,901
50	Special Box - Similar to Space-Glo	HPS	70-watt	Obsolete	(1)	11.42	5.54	2.74	22	87	23	132	3,014	5,779	756	9,549
46	Special Box - Similar to Space-Glo	MV	175-watt	Obsolete	(1)	14.92	8.82	6.02	21	186	47	254	3,759	19,677	3,395	26,831
51	Special Box - Similar to Gardco Hub / Opt C	HPS	Twin 70-watt	Obsolete	(1)	-	-	5.48	-	-	-	0	-	-	-	-
52	Special Box - Similar to Gardco Hub / Opt C	HPS	70-watt	Obsolete	(1)	-	-	2.74	-	-	58	58	-	-	1,907	1,907
53	Special Box - Similar to Gardco Hub	HPS	100-watt	Obsolete	(1)	12.44	7.09	3.92	-	6	15	21	-	510	706	1,216
54	Special Box - Similar to Gardco Hub	HPS	150-watt	Obsolete	(1)	-	8.84	5.66	-	64	45	109	-	6,787	3,056	9,844
55	Special Box - Similar to Gardco Hub / Opt C	HPS	250-watt	Obsolete	(1)	-	-	9.31	-	-	161	161	-	-	17,987	17,987
56	Special Box - Similar to Gardco Hub / Opt C	HPS	400-watt	Obsolete	(1)	-	-	14.88	-	-	125	125	-	-	22,320	22,320
58	Special Box - Gardco Hub	MH	250-watt	Obsolete	(1)	-	12.38	9.03	-	7	32	39	-	1,040	3,468	4,507
59	Special Box - Gardco Hub	MH	400-watt	Obsolete	(1)	-	18.00	14.24	-	26	-	26	-	5,614	-	5,614
69	Dual Wattage 70/100 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	6.72	3.92	-	92	-	92	-	7,414	-	7,414
70	Dual Wattage 100/150 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	6.72	3.92	-	412	-	412	-	33,203	-	33,203
71	Dual Wattage 100/150 - Cobrahead	HPS	150-watt	Obsolete	(1)	-	8.47	5.66	-	362	5	367	-	36,813	340	37,152
95	Special Architectural - KIM SBC Shoebox	HPS	150-watt	Obsolete	(1)	-	9.28	5.66	-	36	66	102	-	4,007	4,483	8,490
80	Special Acorn Type	HPS	70-watt	Obsolete	(1)	11.19	5.54	2.74	24	7	30	61	3,222	465	986	4,673
73	Special GardCo Bronze - Option C Only	HPS	70-watt	Obsolete	(1)	-	-	2.74	-	-	43	43	-	-	1,414	1,414
72	Special GardCo Bronze - Option C Only	MV	175-watt	Obsolete	(1)	-	-	6.02	-	-	319	319	-	-	23,045	23,045
74	Special Acrylic Sphere - Option C Only	MV	400-watt	Obsolete	(1)	-	-	13.42	-	-	4	4	-	-	644	644
25	Early American Post-Top - Black	HPS	70-watt	Obsolete	(1)	7.91	5.55	2.74	1,609	1,404	40	3,053	152,812	93,581	1,315	247,708
43	Rectangular Types - Option C Only	HPS	200-watt	Obsolete	(1)	-	-	7.21	-	-	129	129	-	-	11,161	11,161
5	Incandescent - Option C Only	IND	92-watt	Obsolete	(1)	-	-	2.83	-	-	25	25	-	-	849	849
6	Incandescent - Option C Only	IND	182-watt	Obsolete	(1)	-	-	5.66	-	-	7	7	-	-	475	475
29	Town and Country Post-Top	MV	175-watt	Obsolete	(1)	11.52	8.74	6.02	127	1,330	12	1,469	17,558	139,511	867	157,936
27	Flood	HPS	70-watt	Obsolete	(1)	8.49	5.60	2.74	9	-	7	16	917	-	230	1,147
30	Flood	HPS	100-watt	Obsolete	(1)	9.57	6.76	3.92	49	7	-	56	5,629	568	-	6,197
38	Flood	HPS	200-watt	Obsolete	(1)	13.25	10.11	7.21	192	43	-	235	30,524	5,216	-	35,740
33	Cobrahead - (Non-power door)	HPS	70-watt	Obsolete	(1)	7.93	5.54	2.74	1,712	933	1,147	3,792	162,827	61,979	37,713	262,519
41	Cobrahead - (power door)	HPS	310-watt	Obsolete	(1)	17.79	14.53	11.32	7	20	-	27	1,494	3,486	-	4,980
14	Ornamental - Option C Only	HPS	100-watt	Obsolete	(1)	-	-	3.92	-	-	1,242	1,242	-	-	58,424	58,424
15	Twin Ornamental - Option C Only	HPS	Twin 100-watt	Obsolete	(1)	-	-	7.85	-	-	2,778	2,778	-	-	261,688	261,688
7	Flourescent - Opton C Only	FLR	28-watt	Obsolete	(1)	-	-	1.10	-	-	9	9	-	-	119	119
					(1) No new installations				6,289	6,995	6,574	19,858	$ 779,866	$ 646,943	$ 481,802	$ 1,908,611
									-	-	-	0	$ -	$ -	$ -	$ -
				Standard					29,965	80,054	10,427	120,446	$ 3,740,002	$ 7,836,459	$ 762,141	$ 12,338,602
				Custom					1,285	6,727	1,110	9,122	$ 242,244	$ 705,725	$ 66,478	$ 1,014,447
				Obsolete					6,289	6,995	6,574	19,858	$ 779,866	$ 646,943	$ 481,802	$ 1,908,611
									37,539	93,776	18,111	149,426	$ 4,762,112	$ 9,189,127	$ 1,310,421	$ 15,261,659

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Fixed Charge Prices

Schedule 91 LUMINAIRE CODE	Description of Light	Type	Watts	Category	PROPOSED PRICES Tariff Base Rates OPTION-A	OPTION-B	OPTION-C	9.126 Per Unit KwH
84	Cobrahead - (Minimum of 2500 Power Doors)	HPS	100-watt	Standard	$ -	$ 2.70	$ -	43
85	Cobrahead - (Minimum of 2500 Power Doors)	HPS	150-watt	Standard	-	2.71	-	62
89	Cobrahead - (Minimum of 2500 Power Doors)	HPS	200-watt	Standard	-	2.76	-	79
86	Cobrahead - (Minimum of 2500 Power Doors)	HPS	250-watt	Standard	-	2.73	-	102
87	Cobrahead - (Minimum of 2500 Power Doors)	HPS	400-watt	Standard	-	2.74	-	163
34	Cobrahead - (Not applicable to PD rate)	HPS	100-watt	Standard	5.28	2.80	-	43
35	Cobrahead - (Not applicable to PD rate)	HPS	150-watt	Standard	5.30	2.81	-	62
39	Cobrahead - (Not applicable to PD rate)	HPS	200-watt	Standard	5.72	2.86	-	79
36	Cobrahead - (Not applicable to PD rate)	HPS	250-watt	Standard	5.77	2.87	-	102
37	Cobrahead - (Not applicable to PD rate)	HPS	400-watt	Standard	5.79	2.89	-	163
31	Flood	HPS	250-watt	Standard	6.04	2.90	-	102
32	Flood	HPS	400-watt	Standard	6.06	2.92	-	163
40	Early American Post-Top	HPS	100-watt	Standard	5.68	2.80	-	43
76	Shoebox	HPS	70-watt	Standard	5.90	2.88	-	30
77	Shoebox	HPS	100-watt	Standard	6.11	2.90	-	43
78	Shoebox	HPS	150-watt	Standard	6.38	2.93	-	62
81	Special Acorn	HPS	100-watt	Custom	$ 8.72	$ 3.21	$ -	43
12	Special Acorn - Independence	HPS	100-watt	Custom	8.01	3.09	-	43
13	Special Acorn - Independence	HPS	150-watt	Custom	8.02	3.10	-	62
64	Special Architectural - Capitol Acorn	HPS	100-watt	Custom	12.19	3.45	-	43
65	Special Architectural - Capitol Acorn	HPS	200-watt	Custom	12.24	3.52	-	79
66	Special Architectural - Capitol Acorn	HPS	250-watt	Custom	12.24	3.52	-	102
67	Special Architectural - Capitol Acorn	HPS	150-watt	Custom	12.23	3.51	-	62
82	Special Architectural - Victorian	HPS	150-watt	Custom	8.44	3.19	-	62
49	Special Architectural - Victorian	HPS	200-watt	Custom	8.49	3.20	-	79
83	Special Architectural - Victorian	HPS	250-watt	Custom	8.58	3.21	-	102
98	Special Architectural - Techtra	HPS	100-watt	Custom	14.83	3.93	-	43
99	Special Architectural - Techtra	HPS	150-watt	Custom	14.84	3.94	-	62
88	Special Architectural - Techtra	HPS	250-watt	Custom	20.47	4.00	-	102
96	Special Architectural - KIM Archetype	HPS	250-watt	Custom	-	3.34	-	102
97	Special Architectural - KIM Archetype	HPS	400-watt	Custom	-	3.34	-	163
90	Special Architectural - Westbrooke Acorn	HPS	70-watt	Custom	12.89	3.29	-	30
91	Special Architectural - Westbrooke Acorn	HPS	100-watt	Custom	12.84	3.27	-	43
92	Special Architectural - Westbrooke Acorn	HPS	150-watt	Custom	12.85	3.28	-	62
93	Special Architectural - Westbrooke Acorn	HPS	200-watt	Custom	12.99	3.28	-	79
94	Special Architectural - Westbrooke Acorn	HPS	250-watt	Custom	13.01	3.30	-	102
48	Special Types - Cobrahead	MH	175-watt	Custom	5.50	2.95	-	71
60	Special Types - Flood	MH	400-watt	Custom	6.07	3.05	-	156
47	Special Types - Flood	HPS	750-watt	Custom	8.41	4.00	-	285
9	Special Types - Mongoose	HPS	150-watt	Custom	7.40	3.13	-	62
10	Special Types - Mongoose	HPS	250-watt	Custom	7.49	3.14	-	102
11	Special Types - Mongoose	HPS	400-watt	Custom	7.53	3.16	-	163
2	Alternative Special Acorn - Victorian	QL	85-watt	Alternative	10.62	2.08	-	32
1	Alternative Special Acorn - Victorian	QL	165-watt	Alternative	12.32	2.17	-	60
4	Alternative Special Acorn - Techtra	QL	85-watt	Alternative	13.99	2.20	-	32
3	Alternative Special Acorn - Techtra	QL	165-watt	Alternative	14.72	2.26	-	60

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Fixed Charge Prices

Schedule 91 LUMINAIRE CODE	Description of Light	Type	Watts	Category		PROPOSED PRICES Tariff Base Rates OPTION-A	OPTION-B	OPTION-C	9.126 Per Unit KwH
19	Cobrahead - Option C Only	MV	100-watt	Obsolete	(1)	$ -	$ -	$ -	39
21	Cobrahead	MV	175-watt	Obsolete	(1)	5.37	2.70	-	66
22	Cobrahead	MV	250-watt	Obsolete	(1)	6.32	2.95	-	94
23	Cobrahead	MV	400-watt	Obsolete	(1)	5.48	2.82	-	147
24	Cobrahead	MV	1,000-watt	Obsolete	(1)	6.28	3.13	-	374
50	Special Box - Similar to Space-Glo	HPS	70-watt	Obsolete	(1)	8.68	2.80	-	30
46	Special Box - Similar to Space-Glo	MV	175-watt	Obsolete	(1)	8.90	2.80	-	66
51	Special Box - Similar to Gardco Hub / Opt C	HPS	Twin 70-watt	Obsolete	(1)	-	-	-	60
52	Special Box - Similar to Gardco Hub / Opt C	HPS	70-watt	Obsolete	(1)	-	-	-	30
53	Special Box - Similar to Gardco Hub	HPS	100-watt	Obsolete	(1)	8.52	3.17	-	43
54	Special Box - Similar to Gardco Hub	HPS	150-watt	Obsolete	(1)	-	3.18	-	62
55	Special Box - Similar to Gardco Hub / Opt C	HPS	250-watt	Obsolete	(1)	-	-	-	102
56	Special Box - Similar to Gardco Hub / Opt C	HPS	400-watt	Obsolete	(1)	-	-	-	163
58	Special Box - Gardco Hub	MH	250-watt	Obsolete	(1)	-	3.35	-	99
59	Special Box - Gardco Hub	MH	400-watt	Obsolete	(1)	-	3.76	-	156
69	Dual Wattage 70/100 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	2.80	-	43
70	Dual Wattage 100/150 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	2.80	-	43
71	Dual Wattage 100/150 - Cobrahead	HPS	150-watt	Obsolete	(1)	-	2.81	-	62
95	Special Architectural - KIM SBC Shoebox	HPS	150-watt	Obsolete	(1)	-	3.62	-	62
80	Special Acorn Type	HPS	70-watt	Obsolete	(1)	8.45	2.80	-	30
73	Special GardCo Bronze - Option C Only	HPS	70-watt	Obsolete	(1)	-	-	-	30
72	Special GardCo Bronze - Option C Only	MV	175-watt	Obsolete	(1)	-	-	-	66
74	Special Acrylic Sphere - Option C Only	MV	400-watt	Obsolete	(1)	-	-	-	147
25	Early American Post-Top - Black	HPS	70-watt	Obsolete	(1)	5.17	2.81	-	30
43	Rectangular Types - Option C Only	HPS	200-watt	Obsolete	(1)	-	-	-	79
5	Incandescent - Option C Only	IND	92-watt	Obsolete	(1)	-	-	-	31
6	Incandescent - Option C Only	IND	182-watt	Obsolete	(1)	-	-	-	62
29	Town and Country Post-Top	MV	175-watt	Obsolete	(1)	5.50	2.72	-	66
27	Flood	HPS	70-watt	Obsolete	(1)	5.75	2.86	-	30
30	Flood	HPS	100-watt	Obsolete	(1)	5.65	2.84	-	43
38	Flood	HPS	200-watt	Obsolete	(1)	6.04	2.90	-	79
33	Cobrahead - (Non-power door)	HPS	70-watt	Obsolete	(1)	5.19	2.80	-	30
41	Cobrahead - (power door)	HPS	310-watt	Obsolete	(1)	6.47	3.21	-	124
14	Ornamental - Option C Only	HPS	100-watt	Obsolete	(1)	-	-	-	43
15	Twin Ornamental - Option C Only	HPS	Twin 100-watt	Obsolete	(1)	-	-	-	86
7	Flourescent - Opton C Only	FLR	28-watt	Obsolete	(1)	-	-	-	12

(1) No new installations

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Energy Charge Prices

Schedule 91 LUMINAIRE CODE	Description of Light	Type	Watts	Category	PROPOSED PRICES Tariff Energy Rates OPTION-A	OPTION-B	OPTION-C
84	Cobrahead - (Minimum of 2500 Power Doors)	HPS	100-watt	Standard	$ -	$ 3.92	$ 3.92
85	Cobrahead - (Minimum of 2500 Power Doors)	HPS	150-watt	Standard	-	5.66	5.66
89	Cobrahead - (Minimum of 2500 Power Doors)	HPS	200-watt	Standard	-	7.21	7.21
86	Cobrahead - (Minimum of 2500 Power Doors)	HPS	250-watt	Standard	-	9.31	9.31
87	Cobrahead - (Minimum of 2500 Power Doors)	HPS	400-watt	Standard	-	14.88	14.88
34	Cobrahead - (Not applicable to PD rate)	HPS	100-watt	Standard	3.92	3.92	3.92
35	Cobrahead - (Not applicable to PD rate)	HPS	150-watt	Standard	5.66	5.66	5.66
39	Cobrahead - (Not applicable to PD rate)	HPS	200-watt	Standard	7.21	7.21	7.21
36	Cobrahead - (Not applicable to PD rate)	HPS	250-watt	Standard	9.31	9.31	9.31
37	Cobrahead - (Not applicable to PD rate)	HPS	400-watt	Standard	14.88	14.88	14.88
31	Flood	HPS	250-watt	Standard	9.31	9.31	9.31
32	Flood	HPS	400-watt	Standard	14.88	14.88	14.88
40	Early American Post-Top	HPS	100-watt	Standard	3.92	3.92	3.92
76	Shoebox	HPS	70-watt	Standard	2.74	2.74	2.74
77	Shoebox	HPS	100-watt	Standard	3.92	3.92	3.92
78	Shoebox	HPS	150-watt	Standard	5.66	5.66	5.66
81	Special Acorn	HPS	100-watt	Custom	$ 3.92	$ 3.92	$ 3.92
12	Special Acorn - Independence	HPS	100-watt	Custom	3.92	3.92	3.92
13	Special Acorn - Independence	HPS	150-watt	Custom	5.66	5.66	5.66
64	Special Architectural - Capitol Acorn	HPS	100-watt	Custom	3.92	3.92	3.92
65	Special Architectural - Capitol Acorn	HPS	200-watt	Custom	7.21	7.21	7.21
66	Special Architectural - Capitol Acorn	HPS	250-watt	Custom	9.31	9.31	9.31
67	Special Architectural - Capitol Acorn	HPS	150-watt	Custom	5.66	5.66	5.66
82	Special Architectural - Victorian	HPS	150-watt	Custom	5.66	5.66	5.66
49	Special Architectural - Victorian	HPS	200-watt	Custom	7.21	7.21	7.21
83	Special Architectural - Victorian	HPS	250-watt	Custom	9.31	9.31	9.31
98	Special Architectural - Techtra	HPS	100-watt	Custom	3.92	3.92	3.92
99	Special Architectural - Techtra	HPS	150-watt	Custom	5.66	5.66	5.66
88	Special Architectural - Techtra	HPS	250-watt	Custom	9.31	9.31	9.31
96	Special Architectural - KIM Archetype	HPS	250-watt	Custom	9.31	9.31	9.31
97	Special Architectural - KIM Archetype	HPS	400-watt	Custom	-	14.88	14.88
90	Special Architectural - Westbrooke Acorn	HPS	70-watt	Custom	2.74	2.74	2.74
91	Special Architectural - Westbrooke Acorn	HPS	100-watt	Custom	3.92	3.92	3.92
92	Special Architectural - Westbrooke Acorn	HPS	150-watt	Custom	5.66	5.66	5.66
93	Special Architectural - Westbrooke Acorn	HPS	200-watt	Custom	7.21	7.21	7.21
94	Special Architectural - Westbrooke Acorn	HPS	250-watt	Custom	9.31	9.31	9.31
48	Special Types - Cobrahead	MH	175-watt	Custom	6.48	6.48	6.48
60	Special Types - Flood	MH	400-watt	Custom	14.24	14.24	14.24
47	Special Types - Flood	HPS	750-watt	Custom	26.01	26.01	26.01
9	Special Types - Mongoose	HPS	150-watt	Custom	5.66	5.66	5.66
10	Special Types - Mongoose	HPS	250-watt	Custom	9.31	9.31	9.31
11	Special Types - Mongoose	HPS	400-watt	Custom	14.88	14.88	14.88
2	Alternative Special Acorn - Victorian	QL	85-watt	Alternative	2.92	2.92	2.92
1	Alternative Special Acorn - Victorian	QL	165-watt	Alternative	5.48	5.48	5.48
3	Alternative Special Acorn - Techtra	QL	165-watt	Alternative	5.48	5.48	5.48

Portland General Electric

Schedule 91
Street and Highway Lighting
Luminaire Energy Charge Prices

Schedule 91 LUMINAIRE CODE	Description of Light	Type	Watts	Category		PROPOSED PRICES Tariff Energy Rates OPTION-A	OPTION-B	OPTION-C
19	Cobrahead - Option C Only	MV	100-watt	Obsolete	(1)	-	-	$ 3.56
21	Cobrahead	MV	175-watt	Obsolete	(1)	6.02	6.02	6.02
22	Cobrahead	MV	250-watt	Obsolete	(1)	8.58	8.58	8.58
23	Cobrahead	MV	400-watt	Obsolete	(1)	13.42	13.42	13.42
24	Cobrahead	MV	1,000-watt	Obsolete	(1)	34.13	34.13	34.13
50	Special Box - Similar to Space-Glo	HPS	70-watt	Obsolete	(1)	2.74	2.74	2.74
46	Special Box - Similar to Space-Glo	MV	175-watt	Obsolete	(1)	6.02	6.02	6.02
51	Special Box - Similar to Gardco Hub / Opt C	HPS	Twin 70-watt	Obsolete	(1)	-	-	5.48
52	Special Box - Similar to Gardco Hub / Opt C	HPS	70-watt	Obsolete	(1)	-	-	2.74
53	Special Box - Similar to Gardco Hub	HPS	100-watt	Obsolete	(1)	3.92	3.92	3.92
54	Special Box - Similar to Gardco Hub	HPS	150-watt	Obsolete	(1)	-	5.66	5.66
55	Special Box - Similar to Gardco Hub / Opt C	HPS	250-watt	Obsolete	(1)	-	-	9.31
56	Special Box - Similar to Gardco Hub / Opt C	HPS	400-watt	Obsolete	(1)	-	-	14.88
58	Special Box - Gardco Hub	MH	250-watt	Obsolete	(1)	-	9.03	9.03
59	Special Box - Gardco Hub	MH	400-watt	Obsolete	(1)	-	14.24	14.24
69	Dual Wattage 70/100 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	3.92	3.92
70	Dual Wattage 100/150 - Cobrahead	HPS	100-watt	Obsolete	(1)	-	3.92	3.92
71	Dual Wattage 100/150 - Cobrahead	HPS	150-watt	Obsolete	(1)	-	5.66	5.66
95	Special Architectural - KIM SBC Shoebox	HPS	150-watt	Obsolete	(1)	-	5.66	5.66
80	Special Acorn Type	HPS	70-watt	Obsolete	(1)	2.74	2.74	2.74
73	Special GardCo Bronze - Option C Only	HPS	70-watt	Obsolete	(1)	-	2.74	2.74
72	Special GardCo Bronze - Option C Only	MV	175-watt	Obsolete	(1)	-	6.02	6.02
74	Special Acrylic Sphere - Option C Only	MV	400-watt	Obsolete	(1)	-	13.42	13.42
25	Early American Post-Top - Black	HPS	70-watt	Obsolete	(1)	2.74	2.74	2.74
43	Rectangular Types - Option C Only	HPS	200-watt	Obsolete	(1)	-	-	7.21
5	Incandescent - Option C Only	IND	92-watt	Obsolete	(1)	-	-	2.83
6	Incandescent - Option C Only	IND	182-watt	Obsolete	(1)	-	-	5.66
29	Town and Country Post-Top	MV	175-watt	Obsolete	(1)	6.02	6.02	6.02
27	Flood	HPS	70-watt	Obsolete	(1)	2.74	2.74	2.74
30	Flood	HPS	100-watt	Obsolete	(1)	3.92	3.92	3.92
38	Flood	HPS	200-watt	Obsolete	(1)	7.21	7.21	7.21
33	Cobrahead - (Non-power door)	HPS	70-watt	Obsolete	(1)	2.74	2.74	2.74
41	Cobrahead - (power door)	HPS	310-watt	Obsolete	(1)	11.32	11.32	11.32
14	Ornamental - Option C Only	HPS	100-watt	Obsolete	(1)	-	-	3.92
15	Twin Ornamental - Option C Only	HPS	Twin 100-watt	Obsolete	(1)	-	-	7.85
7	Flourescent - Opton C Only	FLR	28-watt	Obsolete	(1)	-	-	1.10

(1) No new installations

Portland General Electric

Schedule 91
Street and Highway Lighting
Pole Revenue Summary

POLE CODE	Description of Pole	Length (Ft)	OPTION	Category	PROPOSED PRICE	COUNT	ANNUAL REVENUE
57	Fiberglass, black	20	A	Standard	$4.10	1,770	$ 87,068
59	Fiberglass, bronze	30	A	Standard	5.47	2,296	150,691
61	Fiberglass, gray	30	A	Standard	5.49	2,690	177,201
1	Wood, SLO	30 to 35	A	Standard	4.71	3,592	203,015
3	Wood, SLO	40 to 55	A	Standard	5.91	577	40,912
		Total	**A**	**Standard**		**10,924**	**$ 658,887**
58	Fiberglass, black	20	B	Standard	$0.14	4,627	$ 7,773
60	Fiberglass, bronze	30	B	Standard	0.18	5,834	12,601
62	Fiberglass, gray	30	B	Standard	0.18	10,465	22,604
46	Wood, SLO	30 to 35	B	Standard	0.15	930	1,674
47	Wood, SLO	40 to 55	B	Standard	0.20	182	437
		Total	**B**	**Standard**		**22,038**	**$ 45,089**

Portland General Electric

Schedule 91
Street and Highway Lighting
Pole Revenue Summary

POLE CODE	Description of Pole	Length (Ft)	OPTION	Category	PROPOSED PRICE	COUNT	ANNUAL REVENUE
31	Aluminum, Regular	16	A	Custom	$5.83	563	$ 39,405
32	Aluminum, Regular	25	A	Custom	9.48	5,377	611,669
33	Aluminum, Regular	30	A	Custom	10.26	231	28,395
28	Aluminum, Regular	35	A	Custom	11.29	81	10,974
18	Aluminum Davit	25	A	Custom	9.79	78	9,110
6	Aluminum Davit	30	A	Custom	10.44	376	47,058
29	Aluminum Davit	35	A	Custom	11.53	145	20,010
70	Aluminum, Davit with 8-foot Arm	40	A	Custom	14.08	9	1,521
27	Aluminum Double Davit	30	A	Custom	12.56	6	904
65	Aluminum, Fluted Victorian Ornamental	14	A	Custom	11.08	-	-
69	Alunimum, Non-fluted Techtra Ornamental	18	A	Custom	19.81	274	65,135
66	Aluminum, Fluted Ornamental	16	A	Custom	10.60	75	9,540
77	Aluminum, Non-Fluted Orn-Westbrooke	16	A	Custom	15.95	-	-
43	Alunimum, Painted Ornamental	35	A	Custom	27.35	-	-
4	Concrete, Ameron Post-Top	25	A	Custom	23.42	-	-
63	Fiberglass, Fluted Ornamental -Black	14	A	Custom	6.47	624	48,477
67	Fiberglass, Regular - Color may vary	22	A	Custom	3.17	24	913
68	Fiberglass, Regular - Color may vary	35	A	Custom	7.47	133	11,896
16	Fiberglass, Anchor Base -Gray	35	A	Custom	11.95	2	287
35	Fiberglass, Direct Bury with Shroud	18	A	Custom	6.20	2	149
		Total	**A**	**Custom**		**7,999**	**$ 905,443**
34	Aluminum, Regular	16	B	Custom	$0.20	85	$ 203
8	Aluminum, Regular	25	B	Custom	0.32	1,925	7,390
48	Aluminum, Regular	30	B	Custom	0.34	597	2,437
54	Aluminum, Regular	35	B	Custom	0.38	416	1,898
13	Aluminum Davit	25	B	Custom	0.33	94	370
12	Aluminum Davit	30	B	Custom	0.35	1,344	5,644
53	Aluminum Davit	35	B	Custom	0.38	1,188	5,418
76	Aluminum, Davit with 8-foot Arm	40	B	Custom	0.47	164	925
14	Aluminum Double Davit	30	B	Custom	0.42	62	312
71	Aluminum, Fluted Victorian Ornamental	14	B	Custom	0.37	645	2,865
75	Alunimum, Non-fluted Techtra Ornamental	18	B	Custom	0.65	273	2,129
72	Aluminum, Fluted Ornamental	16	B	Custom	0.35	1,465	6,151
78	Aluminum, Non-Fluted Orn-Westbrooke	16	B	Custom	0.52	-	-
44	Alunimum, Painted Ornamental	35	B	Custom	0.90	65	697
5	Concrete, Ameron Post-Top	25	B	Custom	0.78	43	402
64	Fiberglass, Fluted Ornamental -Black	14	B	Custom	0.21	1,807	4,553
73	Fiberglass, Regular - Color may vary	22	B	Custom	0.11	556	734
74	Fiberglass, Regular - Color may vary	35	B	Custom	0.25	1,255	3,765
17	Fiberglass, Anchor Base -Gray	35	B	Custom	0.40	30	144
36	Fiberglass, Direct Bury with Shroud	18	B	Custom	0.21	227	572
		Total	B	Custom		12,239	$ 46,611

Portland General Electric

Schedule 91
Street and Highway Lighting
Pole Revenue Summary

POLE CODE	Description of Pole	Length (Ft)	OPTION	Category	PROPOSED PRICE	COUNT		ANNUAL REVENUE
2	Aluminum Post	30	A	Obsolete	$5.83	610	$	42,705
30	Concrete, Ornamental Post	35 or less	A	Obsolete	9.48	69		7,797
37	Steel, Painted Regular	25	A	Obsolete	9.48	605		68,863
38	Steel, Painted Regular	30	A	Obsolete	10.26	205		25,250
39	Wood, Laminated without Mast Arm	20	A	Obsolete	5.30	3,180		202,259
24	Wood, Laminted SLO Pole	20	A	Obsolete	4.10	375		18,458
41	Wood, Curved laminated	30	A	Obsolete	6.84	1,028		84,351
11	Wood, Painted Underground	35	A	Obsolete	4.71	577		32,605
22	Wood, Painted SLO Pole	35	A	Obsolete	4.71	52		2,913
		Total	**A**	**Obsolete**		**6,701**	**$**	**485,201**
55	Bronze Alloy GardCo	12	B	Obsolete	$0.24	24	$	69
25	Concrete, Ornamental Post	35 or less	B	Obsolete	0.32	290		1,112
7	Steel, Painted Regular	25	B	Obsolete	0.32	350		1,344
49	Steel, Painted Regular	30	B	Obsolete	0.34	42		171
21	Steel, Unpainted with 6-foot Mast Arm	30	B	Obsolete	0.34	55		224
51	Steel, Unpainted with 6-foot Davit Arm	30	B	Obsolete	0.35	44		185
40	Steel, Unpainted with 8-foot Mast Arm	35	B	Obsolete	0.38	125		570
42	Steel, Unpainted with 8-foot Davit Arm	35	B	Obsolete	0.38	19		87
23	Wood, Laminated without Mast Arm	20	B	Obsolete	0.14	2,700		4,536
45	Wood, Curved laminated	30	B	Obsolete	0.25	158		473
26	Wood, Painted Underground	35	B	Obsolete	0.20	1,247		2,992
		Total	**B**	**Obsolete**		**5,053**	**$**	**11,764**
					Total Poles	**82,789**	**$**	**2,152,995**
			A	Standard		10,924	$	658,887
			A	Custom		7,999		905,443
			A	Obsolete		6,701		485,201
					Total A	**25,623**	**$**	**2,049,531**
			B	Standard		22,038	$	45,089
			B	Custom		12,239		46,611
			B	Obsolete		5,053		11,764
			-	No Charge		17,836		-
					Total B	**57,165**	**$**	**103,464**
					Total Poles	**82,789**	**$**	**2,152,995**

Portland General Electric

Schedule 15
Outdoor Area Lighting
Revenue Summary

	By Class Description		Type	Size	PROPOSED PRICES Tariff Base Prices	2009 AVERAGE COUNTS	ESTIMATED ANNUAL REVENUES
	Schedule 15 Residential:						
	15R Luminaires (Lights)						
L21	Cobrahead		MV	175-watt	$11.69	2,646	$ 371,265
L23	Cobrahead		MV	400-watt	19.18	241	55,479
L24	Cobrahead		MV	1000-watt	40.71	9	4,397
L33	Cobrahead - (Non-power door)		HPS	70-watt	8.20	1,015	99,825
L34	Cobrahead - (Not applicable to PD rate)		HPS	100-watt	9.48	2,728	310,199
L35	Cobrahead - (Not applicable to PD rate)		HPS	150-watt	11.24	650	87,706
L39	Cobrahead - (Not applicable to PD rate)		HPS	200-watt	13.24	495	78,651
L36	Cobrahead - (Not applicable to PD rate)		HPS	250-watt	15.39	204	37,675
L41	Cobrahead - (power door)		HPS	310-watt	18.13	4	870
L37	Cobrahead - (Not applicable to PD rate)		HPS	400-watt	20.97	218	54,855
L30	Flood		HPS	100-watt	9.89	71	8,428
L38	Flood		HPS	200-watt	13.33	340	54,379
L31	Flood		HPS	250-watt	15.70	127	23,924
L32	Flood		HPS	400-watt	21.27	36	9,187
L76	Shoebox		HPS	70-watt	9.06	0	-
L77	Shoebox		HPS	100-watt	10.40	566	70,625
L78	Shoebox		HPS	150-watt	12.43	52	7,754
L81	Special Acorn		HPS	100-watt	13.28	326	51,934
L82	Special Architectural - Victorian		HPS	150-watt	14.70	2	353
L49	Special Architectural - Victorian		HPS	200-watt	16.29	0	-
L83	Special Architectural - Victorian		HPS	250-watt	18.49	0	-
L40	Early American Post-Top		HPS	100-watt	10.36	2	249
L48	Special Types - Cobrahead		MH	175-watt	12.27	27	3,977
L60	Special Types - Flood		MH	400-watt	20.63	5	1,238
L47	Special Types - Flood		HPS	750-watt	34.87	0	-
L12	Special Acorn - Independence		HPS	100-watt	12.50	0	-
L13	Special Acorn - Independence		HPS	150-watt	14.24	0	-
L64	Special Architectural - Capitol Acorn		HPS	100-watt	17.11	9	1,858
L65	Special Architectural - Capitol Acorn		HPS	150-watt	20.43	0	-
L66	Special Architectural - Capitol Acorn		HPS	200-watt	22.53	0	-
L67	Special Architectural - Capitol Acorn		HPS	250-watt	18.88	0	-
L98	Special Architectural - Techtra		HPS	100-watt	20.02	0	-
L99	Special Architectural - Techtra		HPS	150-watt	21.76	0	-
L88	Special Architectural - Techtra		HPS	250-watt	31.65	0	-
L96	Special Architectural - KIM Archetype		HPS	250-watt	19.95	0	-
L97	Special Architectural - KIM Archetype		HPS	400-watt	25.32	0	-
L09	Special Types - Mongoose		HPS	150-watt	$13.55	0	-
L10	Special Types - Mongoose		HPS	250-watt	$17.28	0	-
L11	Special Types - Mongoose		HPS	400-watt	$22.87	0	-
	Total Lights	15R			-	9,773	$1,334,830

Portland General Electric

Schedule 15
Outdoor Area Lighting
Revenue Summary

	By Class Description	Type	Size	PROPOSED PRICES Tariff Base Prices	2009 AVERAGE COUNTS	ESTIMATED ANNUAL REVENUES
	Schedule 15 Residential:					
	15R Poles					
P01	Wood, SLO	DB	30 to 35	**$5.98**	1,696	$ 121,705
P03	Wood, SLO	DB	40 to 55	**7.51**	5	451
P11	Wood, Painted Underground	DB	35	**6.99**	56	4,697
P41	Wood, Curved laminated	DB	30	**8.68**	84	8,749
P31	Aluminum, Regular	AB	16	**7.40**	2	178
P32	Aluminum, Regular	AB	25	**12.03**	1	144
P33	Aluminum, Regular	AB	30	**13.03**	7	1,095
P65	Aluminum, Fluted Victorian Ornamental	AB	14	**14.07**	29	4,896
P18	Aluminum Davit	AB	25	**12.43**	0	-
P06	Aluminum Davit	AB	30	**13.25**	0	-
P29	Aluminum Davit	AB	35	**14.65**	0	-
P70	Aluminum, Davit with 8-foot Arm	AB	40	**17.88**	0	-
P27	Aluminum Double Davit	AB	30	**15.95**	0	-
P66	Aluminum, Fluted Ornamental	AB	16	**13.47**	0	-
P69	Alunimum, Non-fluted Techtra Ornamental	AB	18	**25.16**	0	-
P4	Concrete, Ameron Post-Top	AB	25	**29.74**	0	-
P63	Fiberglass, Fluted Ornamental -Black	AB	14	**8.22**	135	13,316
P57	Fiberglass, black	DB	20	**5.20**	169	10,546
P61	Fiberglass, gray	DB	30	**6.97**	894	74,774
P68	Fiberglass, Regular - Color may vary	DB	35	**9.48**	1	114
P16	Fiberglass, Anchor Base -Gray	AB	35	**15.17**	0	-
P35	Fiberglass, Direct Bury with Shroud	DB	18	**7.87**	0	-
	Total Poles	15R		-	3,079	$ 240,665
	Total Schedule 15 R					**$1,575,495**

Portland General Electric

Schedule 15
Outdoor Area Lighting
Revenue Summary

	By Class Description	Type	Size	PROPOSED PRICES Tariff Base Prices	2009 AVERAGE COUNTS	ESTIMATED ANNUAL REVENUES
	Schedule 15 Commercial:					
	15C Luminaires (Lights)					
L21	Cobrahead	MV	175-watt	$11.69	889	$ 124,737
L23	Cobrahead	MV	400-watt	19.18	2,923	672,889
L24	Cobrahead	MV	1000-watt	40.71	171	83,539
L33	Cobrahead - (Non-power door)	HPS	70-watt	8.20	197	19,375
L34	Cobrahead - (Not applicable to PD rate)	HPS	100-watt	9.48	685	77,891
L35	Cobrahead - (Not applicable to PD rate)	HPS	150-watt	11.24	356	48,036
L39	Cobrahead - (Not applicable to PD rate)	HPS	200-watt	13.24	1,266	201,157
L36	Cobrahead - (Not applicable to PD rate)	HPS	250-watt	15.39	561	103,608
L41	Cobrahead - (power door)	HPS	310-watt	18.13	2	435
L37	Cobrahead - (Not applicable to PD rate)	HPS	400-watt	20.97	1,996	502,248
L30	Flood	HPS	100-watt	9.89	119	14,126
L31	Flood	HPS	250-watt	15.70	418	78,742
L32	Flood	HPS	400-watt	21.27	1,214	309,816
L76	Shoebox	HPS	70-watt	9.06	0	-
L77	Shoebox	HPS	100-watt	10.40	31	3,868
L78	Shoebox	HPS	150-watt	12.43	5	746
L81	Special Acorn	HPS	100-watt	13.28	38	6,054
L82	Special Architectural - Victorian	HPS	150-watt	14.70	0	-
L49	Special Architectural - Victorian	HPS	200-watt	16.29	0	-
L83	Special Architectural - Victorian	HPS	250-watt	18.49	0	-
L40	Early American Post-Top	HPS	100-watt	10.36	0	-
L48	Special Types - Cobrahead	MH	175-watt	12.27	0	-
L60	Special Types - Flood	MH	400-watt	20.63	1	248
L47	Special Types - Flood	HPS	750-watt	34.87	109	45,606
L12	Special Acorn - Independence	HPS	100-watt	12.50	4	600
L13	Special Acorn - Independence	HPS	150-watt	14.24	4	684
L98	Special Architectural - Techtra	HPS	100-watt	20.02	0	-
L99	Special Architectural - Techtra	HPS	150-watt	21.76	0	-
L88	Special Architectural - Techtra	HPS	250-watt	31.65	0	-
L96	Special Architectural - KIM Archetype	HPS	250-watt	19.95	0	-
L97	Special Architectural - KIM Archetype	HPS	400-watt	25.32	0	-
L09	Special Types - Mongoose	HPS	150-watt	$13.55	0	-
L10	Special Types - Mongoose	HPS	250-watt	17.28	0	-
L11	Special Types - Mongoose	HPS	400-watt	22.87	0	-
	TOTAL Lights	15C		-	11,536	$ 2,381,891

Portland General Electric

Schedule 15
Outdoor Area Lighting
Revenue Summary

	By Class Description	Type	Size	PROPOSED PRICES Tariff Base Prices	2009 AVERAGE COUNTS	ESTIMATED ANNUAL REVENUES
	Schedule 15 Commercial:					
	15C Poles					
P01	Wood, SLO	DB	30 to 35	$5.98	6,181	$ 443,549
P03	Wood, SLO	DB	40 to 55	7.51	89	8,021
P11	Wood, Painted Underground	DB	35	6.99	114	9,562
P41	Wood, Curved laminated	DB	30	8.68	19	1,979
P31	Aluminum, Regular	AB	16	7.40	26	2,309
P32	Aluminum, Regular	AB	25	12.03	25	3,609
P33	Aluminum, Regular	AB	30	13.03	6	938
P28	Aluminum, Regular	AB	35	14.33	0	-
P65	Aluminum, Fluted Victorian Ornamental	AB	14	14.07	0	-
P18	Aluminum Davit	AB	25	12.43	5	746
P06	Aluminum Davit	AB	30	13.25	0	-
P29	Aluminum Davit	AB	35	14.65	0	-
P70	Aluminum, Davit with 8-foot Arm	AB	40	17.88	0	-
P27	Aluminum Double Davit	AB	30	15.95	0	-
P66	Aluminum, Fluted Ornamental	AB	16	13.47	0	-
P69	Alunimum, Non-fluted Techtra Ornamental	AB	18	25.16	16	4,831
P4	Concrete, Ameron Post-Top	AB	25	29.74	0	-
P63	Fiberglass, Fluted Ornamental -Black	AB	14	8.22	27	2,663
P57	Fiberglass, black	DB	20	5.20	101	6,302
P61	Fiberglass, gray	DB	30	6.97	262	21,914
P68	Fiberglass, Regular - Color may vary	DB	35	9.48	7	796
P16	Fiberglass, Anchor Base -Gray	AB	35	15.17	0	-
P35	Fiberglass, Direct Bury with Shroud	DB	18	7.87	0	-
	Total Poles	15C		-	6,878	$507,219
	Total Schedule 15C					**$2,889,110**
				Total Lights	**21,309**	**$3,716,720**
				Total Poles	**9,957**	**$ 747,884**
					Total Schedule 15	**$4,464,604**

PORTLAND GENERAL ELECTRIC
Example Calculation of PGE Schedule 125 Ratespread and Pricing
Incremental NVPC $70/MWh at the Meter

Grouping	Projected Energy MWH	Energy Price mills/kWh	Generation Revenues	NVPC Price mills/kWh	Base NVPC Revenues	Sch 125 Allocation	Sch 125 Price mills/kWh	Sch 125 Revenues
Schedule 7	7,871,690	63.63	$500,876	44.05	$346,748	$4,509	0.57	$4,487
Schedule 15	24,568	58.57	$1,439	40.55	$996	$13	0.53	$13
Schedule 32	1,531,588	63.56	$97,348	44.00	$67,390	$876	0.57	$873
Schedule 38	67,193	63.41	$4,261	43.90	$2,950	$38	0.57	$38
Schedule 47	22,629	60.85	$1,377	42.13	$953	$12	0.55	$12
Schedule 49	67,825	61.18	$4,149	42.36	$2,873	$37	0.55	$37
Schedule 83-S	5,560,871	63.13	$351,071	43.71	$243,079	$3,161	0.57	$3,170
Schedule 89-S	693,515	63.37	$43,948	43.87	$30,424	$396	0.57	$395
Schedule 83-P	283,465	61.06	$17,309	42.27	$11,983	$156	0.55	$156
Schedule 89-P	1,878,597	60.46	$113,580	41.86	$78,638	$1,023	0.54	$1,014
Schedule 89-T	787,483	59.08	$46,524	40.90	$32,208	$419	0.53	$417
Schedule 91	106,867	58.57	$6,260	40.55	$4,334	$56	0.53	$57
Schedule 92/94	5,346	61.91	$331	42.86	$229	$3	0.56	$3
Schedule 93	578	63.00	$36	43.62	$25	$0	0.57	$0
TOTAL	18,902,214		$1,188,509		$822,831	$10,700		$10,674
					TARGET:	$10,700		

2010 NVPC	$832,644
2009 NVPC	$806,699
Change in NVPC	$25,944
Less Sch 483/489 Fixed Gen. Revenues	$0
Net Change	$25,944
Change with Revenue Sensitive Costs	$26,832
Adjusted 2010 NVPC	$833,531
Base NVPC Revenues	$822,831
Schedule 125	$10,700
Revenue Sensitive Cost Factor	1.0342

PORTLAND GENERAL ELECTRIC
Example Calculation of PGE Schedule 125 Ratespread and Pricing
Incremental NVPC $40/MWh at the Meter

Grouping	Projected Energy MWH	Energy Price mills/kWh	Generation Revenues	NVPC Price mills/kWh	Base NVPC Revenues	Sch 125 Allocation	Sch 125 Price mills/kWh	Sch 125 Revenues
Schedule 7	7,871,690	63.63	$500,876	44.05	$346,748	($337)	(0.04)	($315)
Schedule 15	24,568	58.57	$1,439	40.55	$996	($1)	(0.04)	($1)
Schedule 32	1,531,588	63.56	$97,348	44.00	$67,390	($65)	(0.04)	($61)
Schedule 38	67,193	63.41	$4,261	43.90	$2,950	($3)	(0.04)	($3)
Schedule 47	22,629	60.85	$1,377	42.13	$953	($1)	(0.04)	($1)
Schedule 49	67,825	61.18	$4,149	42.36	$2,873	($3)	(0.04)	($3)
Schedule 83-S	5,560,871	63.13	$351,071	43.71	$243,079	($236)	(0.04)	($222)
Schedule 89-S	693,515	63.37	$43,948	43.87	$30,424	($30)	(0.04)	($28)
Schedule 83-P	283,465	61.06	$17,309	42.27	$11,983	($12)	(0.04)	($11)
Schedule 89-P	1,878,597	60.46	$113,580	41.86	$78,638	($76)	(0.04)	($75)
Schedule 89-T	787,483	59.08	$46,524	40.90	$32,208	($31)	(0.04)	($31)
Schedule 91	106,867	58.57	$6,260	40.55	$4,334	($4)	(0.04)	($4)
Schedule 92/94	5,346	61.91	$331	42.86	$229	($0)	(0.04)	($0)
Schedule 93	578	63.00	$36	43.62	$25	($0)	(0.04)	($0)
TOTAL	18,902,214		$1,188,509		$822,831	($799)	($1)	
					TARGET:	($799)		

2010 NVPC	$821,525
2009 NVPC	$806,699
Change in NVPC	$14,825
Less Sch 483/489 Fixed Gen. Revenues	$0
Net Change	$14,825
Change with Revenue Sensitive Costs	$15,332
Adjusted 2010 NVPC	$822,032
Base NVPC Revenues	$822,831
Schedule 125	($799)
Revenue Sensitive Cost Factor	1.0342

PORTLAND GENERAL ELECTRIC

Example Effects of Schedule 483/489 Large Load Changes

156 aMW Returning to PGE Service

Marginal Net Variable Power Costs are $25/MWH Greater than Embedded NVPC

Schedule	Returning Busbar MWh	Returning Metered MWh	Fixed Generation Price	Change in Fixed Gen. Revenues
Sch 83/89	1,369,686	1,310,377	$18.50	$24,242

2010 NVPC	$897,984
2009 NVPC	$806,699
Change in NVPC	$91,284
Less Sch 483/489 Fixed Gen. Revenues	$24,242
Net Change	$67,042
Change with Revenue Sensitive Costs	$69,335
Sch 483/489 NVPC Contributions	$54,553
Net Rate Impact	$14,782
NVPC to Spread (2009 plus 2010 change)	$876,034
Revenue Sensitive Cost Factor	1.0342

Marginal Net Variable Power Costs are $15/MWH Greater than Embedded NVPC

Schedule	Returning Busbar MWh	Returning Metered MWh	Fixed Generation Price	Change in Fixed Gen. Revenues
Sch 83/89	1,369,686	1,310,377	$18.50	$24,242

2010 NVPC	$884,287
2009 NVPC	$806,699
Change in NVPC	$77,587
Less Sch 483/489 Fixed Gen. Revenues	$24,242
Net Change	$53,345
Change with Revenue Sensitive Costs	$55,169
Sch 483/489 NVPC Contributions	$54,553
Net Rate Impact	$617
NVPC to Spread (2009 plus 2010 change)	$861,869
Revenue Sensitive Cost Factor	1.0342

PORTLAND GENERAL ELECTRIC
Example Effects of Schedule 483/489 Large Load Changes
Additional 95 aMW to Schedule 483/489

Marginal Net Variable Power Costs are $25/MWH Greater than Embedded NVPC

Schedule	Departing Busbar MWh	Departing Metered MWh	Fixed Generation Price	Change in Fixed Gen. Revenues
Sch 83/89	(836,209)	(800,000)	$18.50	($14,800)

2010 NVPC	$750,969
2009 NVPC	$806,699
Change in NVPC	($55,730)
Less Sch 483/489 Fixed Gen. Revenues	($14,800)
Net Change	($40,930)
Change with Revenue Sensitive Costs	($42,330)
Sch 483/489 NVPC Contributions	($33,305)
Net Rate Impact	($9,024)
NVPC to Spread (2009 plus 2010 change)	$764,370
Revenue Sensitive Cost Factor	1.0342

Marginal Net Variable Power Costs are $15/MWH Greater than Embedded NVPC

Schedule	Departing Busbar MWh	Departing Metered MWh	Fixed Generation Price	Change in Fixed Gen. Revenues
Sch 83/89	(836,209)	(800,000)	$18.50	($14,800)

2010 NVPC	$759,331
2009 NVPC	$806,699
Change in NVPC	($47,368)
Less Sch 483/489 Fixed Gen. Revenues	($14,800)
Net Change	($32,568)
Change with Revenue Sensitive Costs	($33,682)
Sch 483/489 NVPC Contributions	($33,305)
Net Rate Impact	($376)
NVPC to Spread (2009 plus 2010 change)	$773,018
Revenue Sensitive Cost Factor	1.0342

PORTLAND GENERAL ELECTRIC
Schedule 123, Summary of Sales Normalization Components

Schedule 7 Tariff Category	Price mills/kWh	2009 MWH	Revenues	Per Cust. Revenues	Monthly Revenues
Transmission & Ancillary	2.25	7,712,700	$17,353,576	$24.22	$2.02
Distribution	28.64	7,712,700	$220,891,735	$308.31	$25.69
Trojan Decommissioning	0.23	7,712,700	$1,773,921	$2.48	$0.21
CIO	0.12	7,712,700	$925,524	$1.29	$0.11
Fixed Generation	19.58	7,712,700	$151,014,671	$210.78	$17.56
Totals	50.82		$391,959,426	$547.07	$45.59
Number of 2009 Customers	716,468				
Revenues per customer	$547.07				
Monthly Revenues	$45.59				
Annual kWh per Customer	10,765				

Schedule 32 Tariff Category	Price mills/kWh	2009 MWH	Revenues	Per Cust. Revenues	Monthly Revenues
Transmission & Ancillary	1.84	1,500,066	$2,760,121	$32.99	$2.75
Distribution Block 1	27.11	1,337,428	$36,257,686	$433.41	$36.12
Distribution Block 2	3.00	162,637	$487,912	$5.83	$0.49
Trojan Decommissioning	0.23	1,500,066	$345,015	$4.12	$0.34
CIO	0.12	1,500,066	$180,008	$2.15	$0.18
Fixed Generation	19.56	1,500,066	$29,341,290	$350.74	$29.23
Totals	46.25		$69,372,033	$829.25	$69.10
Number of 2009 Customers	83,657				
Revenues per customer	$829.25				
Monthly Revenues	$69.10				
Annual kWh per Customer	17,931				

Portland General Electric

Sch. 123, Sales Normalization Adjustment Example

Customer-Based Fixed Costs Revenue

Year	Customers	Monthly Fixed Costs per Customer	Monthly Revenue	Annual Customer-Based Revenue
	A	*B*	*A x B*	*C = A x B x 12*
2009	716,468	$45.59	$32,663,791	$391,965,496
2010	725,066	$45.59	$33,055,759	$396,669,107
2011	733,767	$45.59	$33,452,438	$401,429,250
2012	742,572	$45.59	$33,853,857	$406,246,290
2013	751,483	$45.59	$34,260,110	$411,121,320

Energy-Based Fixed Cost Revenue

Year	Annual Customer kWh [1]	Customers	Total MWH [2]	Volumetric Fixed Costs per kWh	Annual Energy-Based Revenue
	D	*E*	*D x E / 1000*	*F*	*G = D x E x F*
2009	10,765	716,468	7,712,700	$0.05082	$391,959,426
2010	10,692	725,066	7,752,693	$0.05082	$393,991,865
2011	10,622	733,767	7,793,798	$0.05082	$396,080,835
2012	10,553	742,572	7,836,023	$0.05082	$398,226,701
2013	10,485	751,483	7,879,389	$0.05082	$400,430,556

Sales Normalization Adjustment

Year	Customer Based Revenue	Energy Based Revenue	Sales Normalization	Overall Revenue [3]	Percent Change
	C	*G*	*H = C - G*	*I*	*J = H / I*
2009	$391,965,496	$391,959,426	$6,070	$839,815,814	0.00%
2010	$396,669,107	$393,991,865	$2,677,242	$844,170,537	0.32%
2011	$401,429,250	$396,080,835	$5,348,415	$848,646,383	0.63%
2012	$406,246,290	$398,226,701	$8,019,589	$853,244,134	0.94%
2013	$411,121,320	$400,430,556	$10,690,763	$857,966,134	1.25%

(1) *Assumes 6 aMW Energy Efficiency Savings*
(2) *Assumes Annual Load Growth of 1.2%, Assumes Temperature Adjusted Energy Usage*
(3) *Overall Revenue = Estimated Base Rate Equivalent Revenue*