PGE
Portland General Electric Company
Legal Department
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Douglas C. Tingey
Assistant General Counsel

July 19, 2010

Via Electronic Filing and Messenger
Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

Re: UE 215 – PGE 2011 General Rate Case

Attention Filing Center:

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

Rebuttal Testimony of Portland General Electric Company:

- **PGE/1600, 1601/Tooman-Tinker/Revenue Requirement**
- **PGE/1700, 1701/Pope/Power Cost Adjustment Mechanism**
- **PGE/1800/Fetter/Power Cost Adjustment Mechanism**
- **PGE/1900, 1901-1902/Hager-Valach/Cost of Capital**
- **PGE/2000, 2001-2021/Zepp/Return on Equity**
- **PGE/2100, 2101-2103/Kuns-Cody/Pricing**

Also enclosed are an original and three copies of:

- **Work Papers on CD (both confidential and non-confidential portions)**

These documents are being served upon the UE 215 service list. Confidential portions are subject to Protective Order No. 10-056 and therefore not to be posted on the OPUC website.

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

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY
Assistant General Counsel

DCT:cbm
Enclosures
cc: UE 215 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **REBUTTAL TESTIMONY** to be served by electronic mail to those parties whose email addresses appear on the attached service list and by method specified, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No. UE 215.

Dated at Portland, Oregon, this 19th day of July, 2010.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 215

General Rate Case Filing
For Prices Effective January 1, 2011

PORTLAND GENERAL ELECTRIC COMPANY

REBUTTAL TESTIMONY AND EXHIBITS

July 19, 2010

UE 215 / PGE / 1600
Tooman – Tinker

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Alex Tooman
Jay Tinker

July 19, 2010

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions with Portland General Electric Company (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 were previously provided in PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. Our testimony has two purposes. First, we present PGE's revised revenue requirement consistent with:

1) The two non-power cost revenue requirement stipulations filed with the Commission in this case. These stipulations generally resolve PGE's 2011 test year O&M costs and rate base.

2) PGE's requested return on equity (ROE) of 10.5% as initially filed in this case. PGE Exhibit 2000 is the rebuttal testimony of Dr. Zepp, PGE's witness supporting ROE.

3) PGE's requested capital structure of 50% equity and 50% long-term debt. PGE Exhibit 1900 is the rebuttal testimony of Messrs. Hager and Valach regarding capital structure. In addition, their testimony provides an updated cost of long-term debt of 6.065%, which we use in determining the revised revenue requirement.

4) An updated 2011 forecast of net variable power costs (NVPC). This update starts with our April 1, 2010 filing, and updates for forward curves and contracts (as of

June 30, 2010) as well as the updated load forecast for 2011. Finally, the NVPC update reflects the reduction of power costs resulting from the terms of a NVPC stipulation among the parties related to reclassification of certain costs to O&M, or A&G, as appropriate.

5) An updated 2011 load forecast.

Second, we respond to Kroger's objection to PGE's proposed Schedule 145, the Boardman Power Plant Operating Life Adjustment.

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

A. PGE's revised revenue requirement increase in this case is $66.4 million, representing an increase of $114.4 million in the general rate case, offset by a $48.0 million decrease related to NVPC. PGE Exhibit 1601 provides the revised revenue requirement increase. This revised revenue requirement increase compares to PGE's initial rate case filing increase of $125.2 million. Table 1 below summarizes the revised revenue requirement increase in this case:

Table 1 ($ millions)

	General Rate Case	AUT (NVPC)	Total
Original Filing	$157.8	$(32.6)	$125.2
1st Stipulation	$(25.6)	N/A	$(25.6)
2nd Stipulation	$(23.0)	N/A	$(23.0)
NVPC Update/Stip	$5.6	$(15.5)	$(9.9)
Cost of Debt Update	$(0.2)	N/A	$(0.2)
Load Forecast Update	$(0.1)	$0.0	$(0.1)
Total	$114.4	$(48.0)	$66.4

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

Q. How is the remainder of your testimony organized?

A. In Section II we present PGE's updated 2011 NVPC forecast and present the costs reclassified from power costs to O&M (or A&G) pursuant to a stipulation regarding NVPC. In Section III, we present PGE's updated 2011 load forecast. Finally, in Section IV we respond to Kroger's objection to PGE's proposed Schedule 145.

II. Updated NVPC Forecast

Q. What is PGE's updated forecast of NVPC for 2011?

A. PGE's updated forecast of NVPC is $732.3 million for 2011. This compares to PGE's initial forecast of 2011 NVPC of $747.2 million. The confidential work papers to our testimony provide electronic copies of the Monet power cost forecast along with supporting documentation for this update.

Q. Does the updated NVPC forecast reflect any settlements related to NVPC?

A. Yes. The NVPC update reflects the removal of items agreed to by the parties as representing O&M (or A&G) costs rather than NVPC. These costs include:

1) Broker Fees ($696k)
2) Revolving Credit Facility Fees ($1,993k)
3) Margin Net Interest ($564k)
4) Colstrip Lime Costs ($1,577k)
5) Coyote/Port Westward Ammonia Costs ($529k)
6) Boardman Mercury Control Chemicals ($1,872k)

The result of removing these items is a reduction to NVPC of $7.231 million.

Q. Are these the same amounts added back to PGE's revenue requirement as non-NVPC costs in Exhibit 1601?

A. Yes, except that we did not add the Boardman mercury control chemical costs (No. 6 above) because those costs are subject to deferred accounting treatment pursuant to a stipulation regarding the treatment of certain capital costs in 2011. Thus, we have added $5.359 million of costs, segregating items 1 through 3 above as A&G, and 4 through 5 as Production O&M. Our work papers provide support for the items we have added to O&M (or A&G).

Q. Are there other terms to the settlement regarding NVPC?

A. Yes. However, those terms are not reflected in the NVPC update filed with this testimony. PGE intends to file a more comprehensive NVPC update on July 30 that will reflect the remaining terms of the NVPC settlement, along with other updated information.

Q. Does the updated NVPC forecast reflect PGE's updated load forecast?

A. Yes, we incorporated the small reduction in PGE's 2011 cost of service (COS) load forecast into the updated NVPC forecast.

Q. What is the schedule of remaining NVPC updates to be filed in this case?

A. The schedule in UE 215 requires PGE to file Monet updates of NVPC on: July 30, September 20, November 5, and November 15.

III. Updated Load Forecast

Q. What is the basis of PGE's updated load forecast?

A. We updated the load forecast to incorporate the latest economic conditions and forecast, as well as large customers' latest operation plans and business environment that could affect their loads. We used the Office of Economic Analysis' (OEA) June 2010 economic forecast for Oregon and IHS Global Insight's US economic forecast. The load model was re-estimated with historical data through April 2010; the initial filing used the model estimated with data from 1985 through October 2009. The re-estimation is necessary because the economic data have also been revised. The Department of Employment revised Oregon non-farm employment for 2008 and 2009 in February 2010 (its annual "benchmark" revision). In addition, the Bureau of Economic Analysis revised estimates of the US Gross Domestic Products (GDP) several times in a quarter. We, however, retained the basic structure of the model. We provide supporting documentation for PGE's revised load forecast in our work papers.

Q. What is your updated load forecast for 2011?

A. PGE projects deliveries to all end-use customers will be 18,982 million kWh for 2011 on a cycle basis. This compares to PGE's prior delivery forecast of 19,243 million kWh, a decrease of approximately 1.4%.

Table 2 below summarizes the cycle kWh delivery forecast, split out between cost of service, ESS served load, and total deliveries.

Table 2
Total Deliveries in millions of kWh on a cycle basis

Component	2011 Initial	2011 Revised
COS load	18,529	18,521
ESS load	713	460
Total Deliveries	19,243	18,982

Q. What is the impact of the updated load forecast on PGE's revised revenue requirement?

A. The revised load forecast has two impacts on PGE's revised revenue requirement. First, there is a reduction in NVPC due to the small reduction in COS load. As previously mentioned, we include this impact in PGE's updated NVPC forecast for 2011. The second impact is an update in PGE's revenues at current prices. This change results in a small (i.e., less than $100k) modification both to the power cost and non-power cost portions of PGE's proposed revenue requirement increase. PGE Exhibit 1601 demonstrates this adjustment on both the NVPC and general rate case portion of PGE's proposed revenue increase and our work papers provide supporting documentation for this change.

IV. Kroger's Objection to the Boardman Tariff

Q. What does Kroger recommend?

A. Kroger recommends that the Commission reject PGE's Schedule 145, the Boardman Power Plant Operating Life Adjustment.

Q. What is the basis of Kroger's objection to Schedule 145?

A. Kroger states that the depreciation rates and other adjustments associated with early retirement of Boardman should be decided as part of a general rate proceeding rather than through an automatic adjustment clause.

Q. Do you agree with Kroger?

A. No. The closure date of Boardman is highly uncertain and it is dependent on the determinations of various government agencies, including the OPUC. Because of this, PGE believes that it should not have to file a general rate case solely based on one issue over which it has little control. The existence of Schedule 145 allows PGE to place changes in the rates to reflect the operating life assumptions of Boardman following a Commission Order, subject to a review of PGE's compliance filing to that Commission Order.

Q. Are there any other reasons the Commission should not have to evaluate rates overall when implementing a change to Boardman's operating life?

A. Yes. A Commission decision on the matter of the appropriate operating life of Boardman is expected in 2010. The Boardman tariff allows the Commission to make changes in rates related to the Boardman operating life that will likely correspond in time to the adoption of new rates in UE 215. There is no reason to believe that the rates the Commission adopts in UE 215 will not be reasonable during the period of likely adoption of a change pursuant to Schedule 145. Finally, the Boardman tariff allows the Commission an opportunity to maximize the period over which accelerated recovery occurs and thereby minimize the rate impact of a reduction in the depreciable life of the property. Kroger's suggestion of using a full general rate case to implement changes to the Boardman life would unnecessarily delay implementation and increase customer rate impacts.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1601	PGE Revised Revenue Requirement

Exhibit 1601 Portland General Electric Company
2011 Test Year Rate Case
Begins with Initial Filing Revised for Load Forecast, Segregates NVPC Impact from Non-NVPC Impact, then Adjusts for Settlement and NVPC Update
Dollars in 000s

	Non-NVPC Results	NVPC Results	Total Results Before Price Change	Non-NVPC Price Change	NVPC Price Change	Total Results After Price Change	Non-NVPC Adjustments	NVPC Adjustments	Rev Rev w/Adjustments
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Sales to Consumers	906,126	779,727	1,685,853	157,679	(32,535)	1,810,997	(43,234)	(15,501)	1,752,262
Sales for Resale	-		-			-	-	-	-
Other Revenues	20,961		20,961			20,961	1,100	-	22,061
Total Operating Revenues	927,087	779,727	1,706,814	157,679	(32,535)	1,831,958	(42,134)	(15,501)	1,774,323
Net Variable Power Costs		747,192	747,192			747,192	-	(14,907)	732,286
Production O&M (Excludes Trojan)	123,227		123,227			123,227	(4,690)	-	118,537
Trojan O&M	90		90			90	-	-	90
Transmission O&M	12,621		12,621			12,621	(432)	-	12,189
Distribution O&M	84,075		84,075			84,075	(4,281)	-	79,794
Customer & MBC O&M	60,722		60,722			60,722	(2,107)	-	58,614
Uncollectibles Expense	9,609		9,609	713		10,323	(243)	(88)	9,988
OPUC Fees	5,268		5,268	391		5,659	(133)	(48)	5,476
A&G, Ins/Bene., & Gen. Plant	120,548		120,548			120,548	(9,979)	-	110,569
Total Operating & Maintenance	416,160	747,192	1,163,352	1,104	-	1,164,456	(21,866)	(15,043)	1,127,542
Depreciation	216,287		216,287			216,287	(8,443)	-	207,845
Amortization	16,277		16,277			16,277	591	-	16,868
Property Tax	41,724		41,724			41,724	-	-	41,724
Payroll Tax	11,942		11,942			11,942	(206)	-	11,736
Other Taxes	1,396		1,396			1,396	-	-	1,396
Franchise Fees	42,433		42,433	3,150		45,583	(1,067)	(387)	43,789
Utility Income Tax	5,547	12,707	18,255	59,900	(12,707)	65,447	(3,094)	(20)	62,332
Total Operating Expenses & Taxes	751,766	759,899	1,511,666	64,154	(12,707)	1,563,112	(34,085)	(15,451)	1,513,232
Utility Operating Income	175,321	19,828	195,149	93,525	(19,828)	268,846	(8,049)	(50)	261,091
			195,149			268,846			261,091

Exhibit 1601 Portland General Electric Company
2011 Test Year Rate Case
Begins with Initial Filing Revised for Load Forecast, Segregates NVPC Impact from Non-NVPC Impact, then Adjusts for Settlement and NVPC Update
Dollars in 000s

	Non-NVPC Results	NVPC Results	Total Results Before Price Change	Non-NVPC Price Change	NVPC Price Change	Total Results After Price Change	Non-NVPC Adjustments	NVPC Adjustments	Rev Rev w/Adjustments
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Average Rate Base									
Avg. Gross Plant	6,491,337		6,491,337			6,491,337	(95,835)	-	6,395,502
Avg. Accum. Deprec. / Amort	(3,023,949)		(3,023,949)			(3,023,949)	4,985	-	(3,018,964)
Avg. Accum. Def Tax	(353,967)		(353,967)			(353,967)	4,440	-	(349,527)
Avg. Accum. Def ITC	(5)		(5)			(5)	-	-	(5)
Avg. Net Utility Plant	3,113,416	-	3,113,416	-	-	3,113,416	(86,410)	-	3,027,006
Misc. Deferred Debits	47,251		47,251			47,251	(2,920)	-	44,331
Operating Materials & Fuel	72,169		72,169			72,169	-	-	72,169
Misc. Deferred Credits	(50,196)		(50,196)			(50,196)	-	-	(50,196)
Working Cash	58,955		58,955	2,006		60,961	(1,329)	(603)	59,016
Average Rate Base	3,241,595	-	3,241,595	2,006	-	3,243,601	(90,659)	(603)	3,152,326
Rate of Return	5.408%		6.020%			8.289%			8.283%
Implied Return on Equity	4.740%		5.963%			10.500%			10.500%
Effective Cost of Debt	6.077%	6.077%	6.077%	6.077%	6.077%	6.077%	6.065%	6.065%	6.065%
Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Debt Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Weighted Cost of Debt	3.039%	3.039%	3.039%	3.039%	3.039%	3.039%	3.033%	3.033%	3.033%
Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Equity Share of Cap Structure	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%	50.000%
State Tax Rate	6.242%	6.242%	6.242%	6.242%	6.242%	6.242%	6.242%	6.242%	6.242%
Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
Composite Tax Rate	39.057%	39.057%	39.057%	39.057%	39.057%	39.057%	39.057%	39.057%	39.057%
Bad Debt Rate	0.570%	0.570%	0.570%	0.570%	0.570%	0.570%	0.570%	0.570%	0.570%
Franchise Fee Rate	2.517%	2.517%	2.517%	2.517%	2.517%	2.517%	2.499%	2.499%	2.499%
Working Cash Factor	3.900%	3.900%	3.900%	3.900%	3.900%	3.900%	3.900%	3.900%	3.900%
Gross-Up Factor	1.641	1.641	1.641	1.641	1.641	1.641	1.641	1.641	1.641
ROE Target	10.500%	10.500%	10.500%	10.500%	10.500%	10.500%	10.500%	10.500%	10.500%
Grossed-Up COC	11.653%	11.653%	11.653%	11.653%	11.653%	11.653%	11.647%	11.647%	11.647%
OPUC Fee Rate	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%

Exhibit 1601 Portland General Electric Company
2011 Test Year Rate Case
Begins with Initial Filing Revised for Load Forecast, Segregates NVPC Impact from Non-NVPC Impact, then Adjusts for Settlement and NVPC Update
Dollars in 000s

	Non-NVPC Results	NVPC Results	Total Results Before Price Change	Non-NVPC Price Change	NVPC Price Change	Total Results After Price Change	Non-NVPC Adjustments	NVPC Adjustments	Rev Rev w/Adjustments
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Utility Income Taxes									
Book Revenues	927,087	779,727	1,706,814	157,679	(32,535)	1,831,958	(42,134)	(15,501)	1,774,323
Book Expenses	746,219	747,192	1,493,411	4,254	-	1,497,665	(31,335)	(15,431)	1,450,900
Interest Deduction	98,496	-	98,496	61	-	98,557	(2,749)	(18)	95,594
Production Deduction	-		-			-	-	-	-
Permanent Ms	(18,342)	-	(18,342)	-	-	(18,342)	68	-	(18,274)
Deferred Ms	166,877	-	166,877	-	-	166,877	(32,910)	-	133,967
Taxable Income	(66,163)	32,535	(33,628)	153,364	(32,535)	87,201	24,792	(52)	112,136
Current State Tax	(4,130)	2,031	(2,099)	9,573	(2,031)	5,443	1,548	(3)	6,999
State Tax Credits	(3,699)	-	(3,699)	-	-	(3,699)	-	-	(3,699)
Net State Taxes	(7,829)	2,031	(5,798)	9,573	(2,031)	1,744	1,548	(3)	3,301
Federal Taxable Income	(58,334)	30,504	(27,830)	143,791	(30,504)	85,457	23,245	(49)	108,836
Current Federal Tax	(20,417)	10,677	(9,740)	50,327	(10,677)	29,910	8,136	(17)	38,092
Federal Tax Credits	(31,137)	-	(31,137)	-	-	(31,137)	-	-	(31,137)
ITC Amort	-	-	-	-	-	-	-	-	-
Deferred Taxes	64,930	-	64,930	-	-	64,930	(12,854)	-	52,076
Total Income Tax Expense	5,547	12,707	18,255	59,900	(12,707)	65,447	(3,171)	(20)	62,332
SB 408 Ratio - Net to Gross	19.96%	39.06%	12.66%	39.06%	39.06%	18.46%	39.39%	39.06%	18.46%
SB 408 Ratio - Effective Tax Rate	3.07%		8.55%			19.58%			19.27%
Check SB 408 Calc	-		-			-			0
Regulated Net Income	76,825		96,653			170,289			165,497
Check Regulated NI						170,289			165,497

UE 215 / PGE / 1700
Pope

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PCAM

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Maria Pope

July 19, 2010

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I. Introduction and Summary

Q. Please state your name and position.

A. My name is Maria M. Pope. I am the Senior Vice President, Finance, Chief Financial Officer and Treasurer for PGE.

Q. Have you previously testified in this proceeding?

A. Yes, my qualifications are provided in PGE Exhibit 200.

Q. What is the purpose of this rebuttal testimony?

A. The purpose of my testimony is to further support PGE's proposed changes to the Power Cost Adjustment Mechanism (PCAM) and to respond to Staff and intervenors' reply testimony. I first outline our reasoning for the proposed PCAM changes, which more closely aligns the structure to PCAM of our peer utilities. My testimony then addresses the principles articulated by the Commission for PCAMs in UE 180.

Q. Please summarize your recommendation to the Commission?

A. I recommend the Commission approve the changes to the PCAM structure suggested by PGE in opening testimony. The proposed changes will move the PCAM structure closer to the mainstream approach used by Commissions across the country, and is more consistent with the overarching principle of timely recovery of prudently incurred fuel and power costs necessary to serve customers.

II. Discussion

Q. Why is PGE proposing changes to the PCAM?

A. We are concerned about the impact the current PCAM structure has on investors' views of PGE's risk, specifically PGE's ability to recover prudently incurred power costs, which will directly impact our cost of capital that is ultimately borne by customers. We have provided testimony by Mr. Steven M. Fetter, a former Michigan Public Service Commission Chairman, who has testified in a number of jurisdictions across the United States on PCAMs. Mr. Fetter views the current PCAM as an outlier - out of the mainstream for regulated electric utilities. Mr. Fetter reports that the mainstream regulatory practice in designing PCAMs is to allow timely recovery of prudently incurred power costs expended to provide reliable service to customers. He identifies the large asymmetric deadband and earnings test as non-mainstream features. PGE competes for capital with other regulated utilities with more traditional PCAM structures. Because the current PCAM structure is significantly different than the mainstream, with its asymmetrical deadband and earnings deadband, investors consider PGE a higher risk investment, which then results in a higher cost of capital for customers.

Q. Why is it important to understand how investors view the PCAM?

A. The operation of the PCAM determines the extent to which PGE is allowed recovery of its prudent power costs, which then informs investors of the relative risk of investing in PGE compared with another regulated utility. This risk helps drive PGE's cost of capital, which is a significant customer cost especially given PGE's capital requirements which are driven by our short power position and the mandate to meet Oregon's RPS standards.

Q. What have you heard from the investment community about the current PCAM?

A. I routinely speak to and meet with utility investors and they continue to ask about our regulatory environment and express concern about our PCAM. In a June 29, 2010 equity rating report, The Bank of America Merrill Lynch stated, "[o]ur primary concern around POR continues to be the variability caused by its current Power Cost Adjustment Mechanism (PCAM) and associated deadband. The current PCAM deadband is $35 million above the baseline net variable power cost and $17 million below. Due to the company's lack of control over hydro and wind production, POR has historically had meaningful earnings swings due to the PCAM. While we do not expect Oregon to move to a 100% pass through system, we do believe some adjustment to the PCAM, including narrowing the deadband is possible."

Moody's has recently written: "Moody's views automatic adjustment clauses, the most common of which is for fuel and purchased power, the largest component of utility operating expenses, as supportive of utility credit quality and important in reducing a utility's cash flow volatility, liquidity requirements, and credit risk. Fuel adjustment clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. . . . Generally, the more of these clauses a utility has in place, the stronger its scoring should be on this ratings factor and the lower the credit risk. [1]

Other financial analysts have focused on PGE's PCAM in their analyses. For example, Soleil Securities Equity Research called PGE's PCAM "punitive" and a "poor fuel recovery mechanism," creating "unfortunate earning volatility."[2] Wells Fargo Equity Research in a May 6, 2010 report, stated with regard to the rate case, "[w]e are particularly interested to

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[1] Moody's, "Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality" June 18, 2010.
[2] Soleil Securities, Portland General Company Update, July 2, 2010.

see whether parties are open to improvements in the PCAM, which would reduce POR's exposure to purchased power and fuel cost fluctuations. . . ."[3]

Q. Is there any particular component of the PCAM that you hear about most often from investors?

A. Yes. Investors are very concerned about the large asymmetrical deadband, which seems unique to our PCAM. They find it difficult to understand why PGE, unlike so many other regulated utilities that recover all or nearly all incurred power costs, is not allowed to recover prudently incurred power costs expended to serve customers without the application of that unusual deadband.

Q. As structured, the deadbands grow as PGE's investment grows. Does this concern you?

A. Yes. The deadbands are expressed as basis points of ROE and, as such, the gap defined by the deadbands has grown with PGE's rate base growth. This inflates not only the power cost variation that PGE must absorb but also further exacerbates the dollar value of the asymmetry. From an investor viewpoint, the structure increases volatility and therefore, risk.

Q. Do you think the asymmetric nature of the deadbands or the level of asymmetry is warranted?

A. No. The asymmetry originated in UE 165 in a discussion regarding asymmetrical impacts of good versus poor hydro years. In that context it was simply noted that in poor hydro years, energy prices tend to increase whereas in good hydro years, energy prices tend to decline. This leads to an asymmetric effect - it increases the financial impact when hydro is scarce

[3] Wells Fargo Secuirities Equity Research, Portland General Electric, May 6, 2010.

and decreases the benefit when hydro is plentiful. However, there was no evidence in that docket suggesting the potential cost differentials were dynamic based on PGE's investment.

Q. You reference Mr. Fetter's comment that the current PCAM is an outlier. Has PGE undertaken any studies of PCAMs?

A. Yes. We submitted a survey as part of our work papers in our direct testimony.[4] Since then we have updated the survey, provided as PGE Exhibit 1701. The updated survey shows that the mainstream approach, by a considerable margin, is pass through of prudently incurred power costs. Of the companies responding to the survey, 80% have some kind of mechanism and of those, 80% have a pass through, 10.6% have sharing only, 3% have deadbands only, and 6% have deadbands with sharing. To capture this information, we contacted each utility on a complete list of investor owned utilities, and asked them about regulatory treatment of power costs. If the company responded, we included the information on our survey.

Q. Is PGE compensated through its ROE for the increased risk associated with the current PCAM?

A. No. We do not receive an ROE premium due to the increased risk from the current PCAM. I refer to the testimony of Mr. Zepp in PGE Exhibit 1200. Mr. Zepp testifies to the increased risk from our current PCAM in his ROE analysis. Mr. Zepp notes that PGE's requested ROE does not reflect the risks related to the current PCAM. (PGE Exhibit 1200 at 15-16).

Q. Did the Commission articulate principles in adopting the current PCAM design?

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[4] The survey involved online research with SNL.com, regulatory dockets, utility company websites and contacting utilities directly.

A. Yes. In Order No. 07-015, UE 180, the Commission articulated four design principles for the PCAM.[5] They are: 1) the PCAM's application should be limited to unusual events and capture power cost variations that exceed those considered normal business risk; 2) there should be no adjustments if overall earnings are reasonable; 3) the PCAM's application should result in revenue neutrality and 4) the PCAM should operate in the long term.

Q. The mainstream regulatory approach you cite seems at odds with the principles articulated in UE 180 by the Commission. How do you address those principles?

A. PGE disagrees with most of the underlying principles of the current PCAM structure (with the exception of long term operation with which we agree). I refer again to Mr. Fetter's direct and rebuttal testimony and the principle of timely recovery of prudently incurred power costs to reliably serve customers. This is the mainstream guiding principle as evidenced by the most common structure of PCAM - a pass through mechanism. Restructuring the current PCAM to a pass through of power costs would optimize benefits to customers from a cost of capital perspective. However, PGE recognizes the concerns of the other parties to this proceeding and is proposing only incremental movement in the direction of timely cost recovery for prudently incurred power costs expended to provide customers with reliable electricity service.

PGE's proposal continues to meet three of the four principles. The continuation of a deadband supports the principle that the PCAM is limited in application. PGE's proposal contains an earnings test so there would be no adjustment if earnings are reasonable; and the PCAM operates in the long run. We disagree both with the principle that the PCAM should be "revenue neutral" and with the application of that principle in the design of the current

[5] The Order references Order No. 05-1261 (UE 165), in citing the principles.

PCAM. As adopted in UE 165, the principle of revenue neutrality is that the power cost adjustment mechanism should not bias the overall expected level of power cost recovery.[6]

Q. Why do you disagree with the revenue neutrality principle?

A. The revenue neutrality principle is simply at odds with the principle that prices should reflect prudently incurred costs.

Q. Why do you disagree with how the revenue neutrality principle is applied in the current PCAM?

A. The asymmetric deadbands are based on principle that, on an expected basis, amounts captured by the PCAM and passed through to customers either in the form of a refund or charge should be equal over time (ignoring for the moment the earnings test). The Commission has emphasized that this is an important criteria that must be proven by proponents of an asymmetric deadband. For example, in UE 165 PGE and Staff supported a hydro mechanism with asymmetric deadbands but the Commission rejected it because "PGE and Staff provided no evidence that it would be revenue-neutral over the range of hydro conditions." Yet no one has demonstrated that the current PCAM, much less with the PCAM's expanding asymmetric deadbands, is consistent with revenue neutrality.

Q. By adopting the proposed changes to the PCAM, is PGE less incented to control costs?

A. No. As Mr. Fetter states in his testimony, PGE’s incentives for managing the utility come from regulatory oversight and review, with the risk that costs could be disallowed due to imprudence. The $10 million deadband and 90/10 sharing also act as incentives for PGE to control costs and seek to increase efficiency.

[6] Order No. 05-1261 at 10.

Q. CUB quotes a Moody's report as saying it likes PGE's PCAM (CUB/100, Jenks/17-18). What is PGE's interpretation of the language in the Moody's report?

A. Based on numerous conversations with investors and ratings agencies, these entities, given the option for PGE to have no PCAM at all or the current mechanism, view the presence of the current mechanism as a positive factor. However, these entities would view more favorably a mechanism that more closely resembles mainstream power cost recovery mechanisms of most other regulated utilities with whom PGE competes for capital. In its August 2009 report on rating methodology, Moody's noted that the top two credit considerations for regulated utilities are 1) predictability and supportiveness of the regulatory environment, and 2) the ability to timely recover prudently incurred costs and earn returns, with this second point being "perhaps, the single most important. . . .".[7] This is why I think Moody's would view our proposed changes to the PCAM as appropriate regulatory steps.

Q. Does this conclude your testimony?

A. Yes.

[7] Moody's Research: "Rating Methodology: Regulated Electric and Gas Utilities," August 2009.

List of Exhibits

Peer Group Analysis
Power/Gas Cost Adjustment Mechanisms

	Authorized		
	ROE	**Capital Structure**	**Weighted Cost of Equity**
Peer Group	10.60%	48.14%	5.10%
PGE	10.00%	50.00%	5.00%

Adjustment Mechanism	**Count**
Yes	29
No	10
TOTAL	**39**

Mechanisms	**Count (All)**	%	**Count (Electric)**	%	**Count (Gas/Electric)**	%
Pass-through	26	89.7%	16	88.9%	10	90.9%
Sharing only	2	6.9%	1	5.6%	1	9.1%
Deadband only	0	0.0%	0	0.0%	0	0.0%
Deadband w/sharing	1	3.4%	1	5.6%	0	0.0%
	29	**100%**	**18**	**100%**	**11**	**100%**

Peer Group Analysis
Power/Gas Cost Adjustment Mechanisms

	Authorized ROE	Authorized Capital Structure	Authorized Weighted Cost of Equity
Peer Group	10.52%	47.75%	5.02%
PGE	10.00%	50.00%	5.00%

Adjustment Mechanism	Original	Updated	Total
Yes	37	29	66
No	6	10	16
TOTAL	**43**	**39**	**82**

Mechanisms	Original	Updated	Combined	%	Original (Electric)	Updated (Electric)	Combined (Electric)	%	Original (Gas/Electric)	Updated (Gas/Electric)	Combined (Gas/Electric)	%
Pass-through	27	26	53	80.3%	18	16	34	81.0%	1	9	10	58.8%
Sharing only	5	2	7	10.6%	4	1	5	11.9%	0	1	1	5.9%
Deadband only	2	0	2	3.0%	1	0	1	2.4%	1	1	2	11.8%
Deadband w/sharing	3	1	4	6.1%	1	1	2	4.8%	2	2	4	23.5%
	37	**29**	**66**	**100%**	**24**	**18**	**42**	**100%**	**4**	**13**	**17**	**100%**

UE 215 / PGE / 1800
Fetter

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PCAM

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Steven M. Fetter

July 19, 2010

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I. Introduction

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

A. My name is Steven M. Fetter. I am President of Regulation UnFettered. My business address is 1489 W. Warm Springs Rd., Suite 110, Henderson, Nevada 89014.

Q. On Whose behalf are you testifying?

A. I am testifying on behalf of Portland General Electric Co. (“PGE” or the “Company”).

Q. Are you the same Steven M. Fetter who testified earlier in this proceeding?

A. Yes. I am responsible for PGE Exhibit 1300 within this docket before the Oregon Public Utility Commission (“OPUC” or “Commission”).

II. Summary

Q. At the outset, do you have a general comment you wish to make?

A. Yes**.** In this testimony, I rebut the views of Randall J. Falkenberg, testifying on behalf of the Industrial Customers of Northwest Utilities, Mr. Ed Durrenberger, testifying on behalf of the Commission Staff, and Mr. Bob Jenks, testifying on behalf of the Citizens Utility Board. As can be seen, while I disagree with the substance of the opening testimonies of Mssrs. Durrenberger and Jenks, they have presented their views clearly and in a way that helps this Commission to carry out the important and difficult task of weighing pros and cons to determine the appropriate regulatory policy for the state generally and PGE and its customers specifically.

The same cannot be said for Mr. Falkenberg. I disagree with both the substance of Mr. Falkenberg's opening testimony as well as his assertions that I am "naïve" and favor "lax, laissez-faire regulation." I have been involved in the regulatory arena for over twenty-five years – as chairman and member of a commission (appointed by a Democrat and reappointed by a Republican), head of a bond rating utility practice, and now as a consultant to utilities, utility commissions, and consumer advocates. As a decision-maker, I have been involved with some of the most contentious and difficult cases within the regulatory realm, including the abandonment of the Midland nuclear plant and its reconstitution into the world's largest cogeneration facility at the time.

In that Midland case, a joint stipulation between Consumers Power, MPSC staff, and ABATE, an industrial users group, attempted to bring this rather extended litigation to a conclusion. At an expedited hearing it came out that ABATE had cut a secret side deal, agreeing to accept a $7.5 million payment from Consumers Power for litigation expenses.

The MPSC Staff, a signatory to the joint stipulation, knew nothing about that arrangement. The MPSC rejected the settlement. As I recall, with the failure of the joint stipulation, Consumers Power's stock price declined approximately 25% the next day, and litigation continued for over a year. These were hardly the actions of someone naïve as to regulatory process and policy and a lax, laissez-faire regulator.

Mr. Falkenberg talks about many things in his testimony – affiliate transactions, debt versus equity costs, renegade third-party plant operators -- but nowhere does he explain why PGE should not recover from its customers the actual costs of prudently-incurred fuel and purchased power expenditures, as is allowed in most states across the country.

Both Mr. Durrenberger and Mr. Jenks primarily offer views in support of the PCAM as it currently operates. While I address certain aspects of their comments, my rebuttal testimony directed toward Mr. Falkenberg's testimony should be viewed as also responding to their positions.

III. Discussion

Q. Can you sum up your disagreement with the witnesses listed above?

A. Yes, simply stated, I firmly believe that a regulated utility, operating prudently with regard to fuel and purchased power expenditures, deserves full recovery of those costs. This is the mainstream position across the U.S.

Contrary to the witnesses' claims that the OPUC Staff is not up to the challenge of carrying out post-hoc prudence reviews, based upon my personal experience at the Michigan Public Service Commission ("MPSC"), I have much greater faith in the ability of a regulatory staff when assigned a key role in the process. Indeed, Mr. Falkenberg lists several instances where findings of imprudent utility behavior (and related cost disallowances) have been found, illustrating that it can be done! I note that a majority of commissions across the country set their internal staff structures to be able to carry out prudence reviews of fuel and purchased power expenditures to ensure that customers pay no more than they should, and that companies recover only what they are entitled to receive.

Q. Mr. Falkenberg testifies that PCAM issues should be treated as all other ratemaking issues with a utility merely having an opportunity to recover its costs. Do you agree?

A. No. Fuel and power costs are not items upon which PGE receives a return. Any utility should receive dollar-for-dollar recovery for prudently-incurred fuel and power costs, or as close to it as the regulatory process can provide. Mr. Falkenberg muddies the discussion through his voluminous discussion of the ratemaking process and how it only provides a regulated utility an "opportunity" to recover its costs and earn an appropriate return. When we are addressing the PCAM, we are not talking about determining an appropriate return on investment. I analogize the PCAM to when a neighbor asks you to pick up a gallon of milk for them at the store. Yesterday the gallon was $2.25, today it's $2.35, and tomorrow it may be $2.15. No one would ever argue that you should not receive from the neighbor the $2.35 you actually paid for the milk. That is what is happening when PGE procures fuel and purchased power on behalf of its customers, without a return on the funds expended. Indeed, I find it somewhat incredible that one of the arguments Mr. Falkenberg uses to support continuation of the current PCAM is that PGE has over-recovered its fuel and purchased power costs during the past two years.

Q. As Mr. Falkenberg notes, doesn't the fact that the last two PCAM proceedings resulted in settlements reflect that PGE views the PCAM structure as "well-defined, and the process lacking in controversy" (Falkenberg/2)?

A. Not at all. Whether PGE agrees with the policy underlying the current PCAM or not, the Company is required to follow its strictures unless and until they are modified. Those settlements merely reflect that the parties were able to agree to the mathematical calculations within the PCAM.

Q. In arguing against full recovery of fuel and purchased power costs, Mr. Falkenberg notes that there are many utilities that deal with their internal costs without any conventional regulatory oversight, such as National or State-owned utilities, many Cooperatives and Municipal Utilities, as well as Federal Agencies (Falkenberg/4). Does He have a point there?

A. No. From my experience, most if not all of those governmental or nonprofit entities finance their operations with tax-exempt debt. That debt has bond indentures and strict covenants that limit the ratemaking flexibility of those self-regulating entities, so as to provide adequate cash flow from rates to ensure that principal and interest are paid on a timely basis, with a small reserve fund set aside to deal with unforeseen occurrences. Basically, that structure is predicated on delivering a precise amount of funds through the ratemaking process – *it is a cost-based system.* As such, even though those entities are self-regulating, it is incumbent upon them to move rates up and down to reflect variability in power supply costs and other O&M expenditures that might not be covered by the small reserve fund.[1] Thus, those systems bear a much closer resemblance to my call for a PCAM that aims directly at recovery of actual prudent fuel costs than it does to traditional rate of return ratemaking, which by its very name is inconsistent with what a PCAM aims to do – that is, to provide fuel and purchased power cost recovery without an equity return.

Q. Mr. Falkenberg says you have a "rather naive view of the efficiency of regulation in identifying and disallowing imprudent costs" and that you are "Proposing a rather lax, laissez-faire form of regulation." Would you agree with his assessment?

A. If believing that utility regulation can be carried out efficiently with fair results for all stakeholders is a fanciful aspiration, call me naïve. At the MPSC, I led a commission that carried out a plan and reconciliation process for all of the state's electric and natural gas utilities on an annual cycle. Contrary to Mr. Falkenberg's statement that I am trying to play it both ways with future versus historical test years, an annual plan and reconciliation process, by its very nature, can only work that way: through use of forecasted data going in and historical data coming out.

I also must reject the "lax, laissez-faire regulation" label Mr. Falkenberg attempts to pin on me. I don't understand how advocating for a regulatory process that seeks to match up

[1] See, for example, S&P Research: "Tacoma, Washington; Retail Electric," September 9, 2009 ("Rate-setting, issuing debt, and other matters require formal city council approval. …We believe the city has generally demonstrated a commitment to sound financial performance, by quickly increasing rates when rising costs indicate that it is necessary to do so. This was particularly evident during 2000 and 2001, when Tacoma adopted a temporary 50% rate surcharge in response to rising purchase-power costs to preserve its financial position.")

prudent actual costs with timely recovery would fall into that category. Rather, I would think that a process under which a utility over-recovers for two years in a row – and potentially could under-recover when hydro conditions turn negative in the future -- would more appropriately bear that description.

Q. Mr. Jenks testifies that, under a modified PCAM, "PGE will no longer have an incentive to control its costs." (Jenks/4) Do you agree?

A. No I do not. Under the PCAM modifications proposed by PGE, the Company will face one of two fates. At best, It will either recover almost all of its actual costs (limited due to 90-10 and deadband effects); at worst it will undertake fuel and purchased power procurement activities, for which it does not receive a return, and be found to have acted imprudently with a portion of its actual expenditures disallowed. I have looked at this situation every which way, today as well as when I was a utility regulator, and I cannot for the life of me see why PGE or any other utility would not try to carry out these activities appropriately. The Company cannot gain by acting without due care, but it can lose if found to have acted imprudently. I just don't understand what would motivate a utility to act in an inappropriate or imprudent manner, when there is nothing to be gained by doing so. None of the witnesses opposing PGE's proposed modifications have explained where such a motivation would come from, and, more so, what could be gained by such an approach.

Q. Mr. Jenks states that your testimony "Makes clear that the purpose of the changes that PGE is proposing in the PCAM is to reduce the chance of the company earning less than its authorized amount." (Jenks/5) Do you agree?

A. No. I don't know how he can say that, since I do not believe that earnings should enter into the fuel cost recovery equation either as a positive or negative driver. Indeed, as I noted in my direct testimony, of all the commissions using a PCAM, only Indiana makes an earnings analysis within its PCAM, and then only in a much more attenuated fashion than what currently exists here. Perhaps Mr. Jenks was reading my quote from S&P in which the agency mentioned two negative rating factors: "a weak power cost mechanism and chronic under-earning of authorized returns."[2] I view those as two distinct negative items affecting PGE's financial health and credit ratings.

Q. Both Mr. Falkenberg and Mr. Jenks talk about evil doings at the Rating Agencies, and that Moody's think the PCAM is fine just the way it is. (Falkenberg/13-14; Jenks/17-18) Do you have thoughts on their comments?

A. Yes. The track record of the rating agencies over the past ten years has been less than perfect. I believe negative occurrences at the rating agencies have resulted in much stricter behavior internally within the agencies and closer scrutiny externally by the government and the financial community. The agencies remain a key cog within the operations of the financial system. Ironically, I believe the manner in which the agencies are run today following those mistakes is more transparent and careful than they have ever operated before, and that continued reliance on their ratings and published statements is totally appropriate.

With regard to Moody's and PCAMs, I am sure Moody's views the current PCAM more positively than no PCAM at all. I am also confident that Moody's would view a PCAM with PGE's proposed modifications even more positively, since it would more closely track Moody's view that:

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[2] S&P Research: "Portland General Electric Co. Corporate Credit Rating Lowered to 'BBB' on Weak Economy; Outlook Revised to Stable," January 29, 2010.

> "The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions."[3]

Q. In conclusion, I can't help but ask how do you view Mr. Falkenberg's new Coke example?

A. Somehow Mr. Falkenberg attempts to undercut my prudence discussion by pointing to New Coke as "arguably a prudent decision," but one that "did not result in Coca Cola Company making a profit on the product." (Falkenberg/ 5) Interestingly, from the time of Coca Cola's introduction of New Coke on April 23, 1985 until the day before it was discontinued 79 days later on July 10, 1985, Coca Cola's common stock price actually rose. So I'm not sure how anyone can opine conclusively whether New Coke was a failure from a marketing perspective, or that it represented success in that Coca Cola undertook a huge risk, failed, but maintained and indeed improved its market capitalization. Thankfully, that question doesn't have to be answered here as it is irrelevant to the Commission's task at hand.

I do, however, see other relevance to the New Coke example. Coca Cola was able to attempt a new market strategy with New Coke, assess that the product was not working, and shortly thereafter abandon distribution and sale of the product. PGE is legally barred from acting in a similar fashion. Even if a particular part of the Company's system is not meeting its cost of service or is proving to be problematic in other ways, PGE has an obligation to serve and thus cannot abandon that portion of its service territory. Moreover, even if PGE disagrees with the PCAM ordered by this Commission because it does not provide recovery

[3] Moody's Research: "Rating Methodology: Regulated Electric and Gas Utilities," August 2009.

of 100% of its prudently-incurred fuel and purchased power costs (unfortunately, a characteristic of both the current and proposed PCAMs), the Company is not allowed to unilaterally decide that, for business reasons, it will no longer procure power supply on behalf of its customers. Clearly, PGE operates within a totally different business landscape than does Coca Cola and other competitively-based corporations.

Q. Do you have concluding thoughts?

A. Yes I do. Timely recovery of prudently-incurred expenditures made by a regulated utility on behalf of its customers is important, both in a business sense as well as to investors, those who provide the capital needed to enhance and maintain system infrastructure. I respectfully suggest that PGE should be allowed to receive full (or here, closer to full) recovery for prudently meeting the fuel and purchased power obligations it has been assigned under the "regulatory compact."

Q. Dose this conclude your Rebuttal Testimony?

A. Yes it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Cost of Capital

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Patrick G. Hager
William J. Valach

July 19, 2010

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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 in PGE Exhibit 1100.

My name is William J. Valach. I am the Director of Investor Relations for PGE. I am responsible for managing the relationships and communications with PGE's shareholders and the investing public. My qualifications appear in PGE Exhibit 1100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is three-fold. First, we provide an update to PGE's test year cost of long-term debt and cost of capital estimates. Second, we respond to the testimony of OPUC Staff (Staff) witnesses Jorge Ordonez (Staff Exhibit 1000) and Steve Storm (Staff Exhibit 900) regarding PGE's cost of debt and capital structure. Finally, we respond to the testimony of ICNU-CUB witness Michael Gorman (ICNU-CUB Exhibit 200) regarding PGE's capital structure.

II. Updated Cost of Long-term Debt and Cost of Capital Estimates

Q. Has PGE completed the long-term debt issuances that were forecast at the time of your direct testimony?

A. Yes. PGE has completed the issuance of three series of bonds. On March 11, 2010, PGE remarketed two series of pollution control bonds (PCB) due in 2033 with coupon rates of 5.000% each and a total principal amount of $121.4 million. On June 15, 2010, PGE closed the issuance of $58.0 million of first mortgage bonds (FMB) due in 2017 with a coupon rate of 3.810%.

Q. What is your updated cost of long-term debt recommendation?

A. We recommend a cost of long-term debt of 6.065%.

A. Response to Staff Witness Ordonez

Q. How does the cost of long-term debt presented here compare with that presented by Staff witness Ordonez in Staff Exhibit 1000?

A. Mr. Ordonez recommends a cost of long-term debt of 6.071% subject to an update in order to incorporate PGE's then-planned June 15, 2010, bond issuance (Staff Exhibit 1000, pages 5-6). Our recommendation of 6.065% includes the update that Mr. Ordonez referred to in his testimony and reflects the lower actual principal amount and coupon rate for this bond series relative to those included in Mr. Ordonez's Staff Exhibit 1002, page 6. A majority of the expenses associated with this issuance are known at this time, however, PGE is still in the process of finalizing several expenses. An estimate of those expenses, provided by PGE's Finance Department, has been included in the updated cost of long-term debt estimate presented here. The estimated expenses are minor and are not expected to impact the overall cost of long-term debt.

Q. How does PGE's current cost of long-term debt estimate compare with that presented in PGE Exhibit 1100?

A. PGE's cost of long-term debt estimate is 1.2 basis points lower than that presented in PGE Exhibit 1100. PGE's estimated cost of long-term debt is currently 6.065%. This compares with the estimate of 6.077% presented in PGE Exhibit 1100. PGE's updated detailed cost of long-term debt estimate for the 2011 test year is presented in PGE Exhibit 1901.

Q. Does PGE anticipate the issuance of additional long-term debt prior to year-end 2011?

A. No.

Q. What is your overall recommended cost of capital?

A. We request and support an 8.283% cost of capital for the 2011 test year. This cost of capital includes a 10.5% required return on equity (RROE) based on the recommendations of Dr. Zepp in PGE Exhibit 2000 and adjustments applied at the direction of PGE's CEO. These adjustments were discussed in detail in PGE Exhibit 100. This point estimate is for revenue requirement purposes and is based on our recommended range of 8.283% to 9.002% for PGE's cost of capital and a recommended range of 10.500% to 11.938% for PGE's RROE. Table 1 below shows the recommended cost of the two components of PGE's capital, long-term debt and common equity. Table 1 also shows PGE's 2011 target capital structure.

Table 1
PGE's Weighted Cost of Capital
Test Year 2011

Component	Percent of Capital *	Component Cost	Weighted Cost
Long-term Debt	50.00%	6.065%	3.033%
Common Equity	50.00%	10.500%	5.250%
Total	**100.00%**		**8.283%**

* "Percent of Capital" reflects PGE's long-term targeted capital structure of 50% long-term debt and 50% common equity, and is used to calculate PGE's weighted average cost of capital ("Weighted Cost").

III. PGE's Capital Structure

Q. What capital structure did you use in determining PGE's cost of capital for the 2011 test year?

A. We continue to use PGE's current regulated capital structure of 50% long-term debt and 50% common equity, as approved in Order No. 07-015 and Order No. 09-020 (affirming a stipulation reached among the parties in that docket). This capital structure represents PGE's long-term target, although the actual capital structure may fluctuate around this level.

Q. How has PGE's year-end capital structure compared with the target?

A. PGE's year-end capital structure has fluctuated around the target, as expected. Table 2 below summarizes PGE's actual year-end capital structure for 2007–2009, as well as the forecast year-end capital structure for 2010 and 2011. At year-end 2007 and 2008, the equity ratio was above 50%. At year-end 2009 and 2010, the equity ratio was, and is expected to be, below 50%. By year-end 2011, PGE's equity ratio is expected to again exceed 50%. The average equity ratio over this period of years is 50.8%. While these annual values vary, over any three consecutive years the equity ratio either exceeds or equals the 50% target; evidence of PGE's statements that in any given year the ratio will fluctuate and that the target is long-term in nature. This information is also provided as PGE Exhibit 1902.

Table 2
PGE's Year-end Capital Structure
2007 - 2011

Component	2007 [1]	2008 [1]	2009 [1]	2010 [2]	2011 [2]
Debt Ratio [3]	49.9%	46.2%	50.3%	53.2%	46.6%
Equity Ratio	50.1%	53.8%	49.7%	46.8%	53.4%

[1] Actual per PGE 10-K
[2] Forecast per PGE Integrated Model
[3] Long-term debt net of portion due within one year of year-end

Q. Why is PGE's actual capital structure not likely to match the long-term target exactly?

A. PGE's capital expenditure program creates the need for on-going external financing. This financing does not take place evenly throughout the year, and, when financing deals are executed, PGE does not issue equal parts long-term debt and common equity (proportions equivalent to the target) in order to maintain the target capital structure. Rather, PGE issues whichever capital component is determined to be the most cost-effective given market conditions at that time while still meeting the financing needs and allowing the capital structure to remain near the target. Over any short time period, the capital structure will likely contain a greater amount of either long-term debt or common equity, depending on recent financing activities.

A. Response to Staff Witness Storm

Q. What capital structure does Staff witness Storm recommend for PGE?

A. Mr. Storm recommends a 50% long-term debt and 50% common equity capital structure for ratemaking purposes (Staff Exhibit 900, page 46).

Q. Do you agree with Mr. Storm's recommendation?

A. Yes. Mr. Storm's testimony indicates, as we note above, that PGE's actual capital structure can vary from the long-term target; however, the target capital structure is reasonable (Staff Exhibit 900, page 45).

B. Response to ICNU-CUB Witness Gorman

Q. What capital structure does ICNU-CUB witness Gorman recommend for PGE?

A. Mr. Gorman recommends a 52.19% long-term debt and 47.81% common equity capital structure for ratemaking purposes (ICNU-CUB Exhibit 200, page 22).

Q. Has Mr. Gorman offered testimony regarding PGE's capital structure in prior proceedings?

A. Yes. Mr. Gorman presented testimony addressing PGE's capital structure in UE 180 (UE 180, ICNU-CUB Exhibit 300).

Q. What capital structure did PGE propose in UE 180?

A. PGE proposed the use of the forecasted capital structure for the 2007 test year in UE 180, 46.7% long-term debt and 53.3% common equity (UE 180, PGE Exhibit 2700, page 5).

Q. What did Mr. Gorman propose for PGE's capital structure in UE 180?

A. Mr. Gorman recommended that a hypothetical capital structure of 50% long-term debt and 50% common equity be approved for PGE in UE 180.[1]

Q. Did the sponsors of Mr. Gorman's testimony in UE 180 support the approval of a hypothetical 50% long-term debt and 50% common equity capital structure for PGE?

A. Yes. In UE 180, Mr. Gorman's testimony was sponsored jointly by ICNU and CUB. ICNU supported Mr. Gorman's proposed capital structure and stated that, "[r]emoving the preferred equity would result in a capital structure with 50% equity and 50% debt" (UE 180, Opening Brief of ICNU, page 36). CUB also supported Mr. Gorman in UE 180 stating that his, "proposed capital structure is reasonable" (UE 180, CUB Opening Brief, page 31).

Additionally, ICNU indicated in their opening brief that the Commission should not adopt the 2007 capital structure forecasted by PGE because it, "conflicts with the assumption about a 2007 capital structure in PGE's internal planning", referring to a data request in which PGE indicated its plans to "manage its capital structure to achieve a 50%

[1] Mr. Gorman recommended that the Commission approve a capital structure of "approximately 50.00% common equity, 0.29% preferred stock, and 49.71% long-term debt" (UE 180, ICNU-CUB Exhibit 300, page 8). Note that PGE no longer has any preferred stock outstanding.

common equity ratio" (UE 180, Opening Brief of ICNU, pages 36 and 38). PGE continues to manage its capital structure to achieve a 50% common equity ratio.

Q. Does Mr. Gorman continue to support the use of a hypothetical, or target, capital structure for ratemaking purposes in this docket, as he did previously in UE 180?

A. No. Mr. Gorman now holds the opposite position. His testimony states that, "[i]mportantly, the Company's projected test year capital structure is not based on its projected 2011 test year capital structure" (ICNU-CUB Exhibit 200, page 20).

Q. Has PGE's approach for determining its requested regulated capital structure changed since UE 180 as well?

A. Yes. As stated above, PGE supported the use of the forecasted test year capital structure in UE 180. Since that time, however, PGE has been consistent with the Commission Order in that docket, which established the use of the 50% long-term debt and 50% common equity regulated capital structure.

Q. Is the Commission required to adopt PGE's actual capital structure for ratemaking purposes?

A. No, it is not. Order No. 07-015 stated that the, "Commission is not required to adopt PGE's actual capital structure" (Order No. 07-015, page 30).

Q. What rationale does Mr. Gorman provide for the Commission to discontinue the use of PGE's target capital structure for ratemaking purposes?

A. Mr. Gorman argues that the Commission should not continue using PGE's target capital structure for ratemaking purposes because it overstates the equity ratio and results in an increased revenue requirement relative to the capital structure that he proposes (ICNU-CUB 200, page 21). Mr. Gorman made the opposite argument in UE 180 and advocated for the use of a hypothetical 50% long-term debt and 50% common equity capital structure with <u>less</u> equity than PGE's forecasted capital structure (UE 180, ICNU-CUB Exhibit 300, page 8).

Q. Does the forecast relied upon by Mr. Gorman to determine his capital structure recommendation indicate that PGE expects its equity ratio to remain below the 50% target throughout the test year?

A. No. As indicated in the forecast relied upon by Mr. Gorman, and stated in PGE Exhibit 1100, PGE's forecast equity ratio is expected to exceed 50% by the end of 2011 (PGE Exhibit 1100, page 25). This is consistent with PGE's and Staff's observations that PGE's equity ratio fluctuates over time, and, thus, the target capital structure is reasonable for ratemaking purposes.

Q. What is your capital structure recommendation?

A. We agree with Staff witness Storm's recommendation that the Commission continue to authorize the use of PGE's target capital structure of 50% long-term debt and 50% common equity for ratemaking purposes.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
1901	PGE's Updated Cost of Long-Term Debt Estimate - 2011
1902	PGE's Capital Structure Year-end 2005–2011

Cost of Long-Term Debt

December 31, 2011
Updated July 8, 2010

(A)	Ledger (B)	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)	F/N	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	G11501	Series MTN	9.310% 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	1.106%	0.104%
2	G21195	PCB	Trojan 90A Fixed	1-Jul-98	1-Aug-14	16	5.250%	$9,600,000	$103,771	$184,980	1	$9,311,249	5.537%	96.992%	$9,600,000	$9,311,249	0.531%	0.029%
3	G11514	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	5.528%	0.377%
4	G11516	Series VI MTN	5.625% Series	4-Aug-03	1-Aug-13	10	5.398%	$50,000,000	$408,842	$1,946,809	2	$47,644,349	6.032%	95.289%	$50,000,000	$47,644,349	2.764%	0.167%
5	G11517	Series VI MTN	6.750% Series	4-Aug-03	1-Aug-23	20	6.523%	$50,000,000	$521,342	$1,946,809	2	$47,531,849	6.985%	95.064%	$50,000,000	$47,531,849	2.764%	0.193%
6	G11518	Series VI MTN	6.875% Series	4-Aug-03	1-Aug-33	30	6.648%	$50,000,000	$521,342	$1,946,809	2	$47,531,849	7.046%	95.064%	$50,000,000	$47,531,849	2.764%	0.195%
7	G11521	FMB	6.310% Series	26-May-06	1-May-36	30	6.310%	$175,000,000	$1,270,865	$6,199,472	3	$167,529,663	6.640%	95.731%	$175,000,000	$167,529,663	9.674%	0.642%
8	G11519	FMB	6.260% Series	26-May-06	1-May-31	25	6.260%	$100,000,000	$723,857	$4,132,982	3	$95,143,161	6.662%	95.143%	$100,000,000	$95,143,161	5.528%	0.368%
9	G11522	FMB	5.800% Series	16-May-07	1-Jun-39	32	5.800%	$170,000,000	$1,447,420	$50,969	4	$168,501,611	5.861%	99.119%	$170,000,000	$168,501,611	9.397%	0.551%
10	G11523	FMB	5.810% Series	19-Sep-07	1-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	7.186%	0.424%
11	G11524	FMB	5.800% Series	12-Dec-07	1-Mar-18	10	5.800%	$75,000,000	$637,500	$0		$74,362,500	5.912%	99.150%	$75,000,000	$74,362,500	4.146%	0.245%
12	G11525	FMB	4.450% Series	15-Apr-08	1-Apr-13	5	4.450%	$50,000,000	$915,100	$1,990,993	5	$47,093,907	5.806%	94.188%	$50,000,000	$47,093,907	2.764%	0.160%
13	G11526	FMB	6.500% Series	15-Jan-09	15-Jan-14	5	6.500%	$63,000,000	$412,020	$0		$62,587,980	6.656%	99.346%	$63,000,000	$62,587,980	3.483%	0.232%
14	G11526	FMB	6.800% Series	15-Jan-09	15-Jan-16	7	6.800%	$67,000,000	$438,180	$0		$66,561,820	6.919%	99.346%	$67,000,000	$66,561,820	3.704%	0.256%
15	G11527	FMB	6.100% Series	13-Apr-09	15-Apr-19	10	6.100%	$300,000,000	$2,608,223	$0	6	$297,391,777	6.218%	99.131%	$300,000,000	$297,391,777	16.584%	1.031%
16	G11528	FMB	5.430% Series	3-Nov-09	3-May-40	30.5	5.430%	$150,000,000	$1,034,283	$0		$148,965,717	5.477%	99.310%	$150,000,000	$148,965,717	8.292%	0.454%
17	G11529	FMB	3.460% Series	15-Jan-10	15-Jan-15	5	3.460%	$70,000,000	$473,458	$0	7	$69,526,542	3.609%	99.324%	$70,000,000	$69,526,542	3.870%	0.140%
18	G211851	PCB	Clstrp 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$97,800,000	$688,885	$1,521,911	8	$95,589,204	5.168%	97.739%	$97,800,000	$95,589,204	5.406%	0.279%
19	G211861	PCB	Brdmn 98A Fixed	11-Mar-10	1-May-33	23	5.000%	$23,600,000	$166,234	$912,065	8	$22,521,701	5.346%	95.431%	$23,600,000	$22,521,701	1.305%	0.070%
20	G11531	FMB	3.810% Series	15-Jun-10	15-Jun-17	7	3.810%	$58,000,000	$379,620	$0		$57,620,380	3.918%	99.345%	$58,000,000	$57,620,380	3.206%	0.126%
			Annual expense from loss on reacquired debt							$391,732		($391,732)						
			Totals					$1,809,000,000	$25,860,072	$21,225,531		$1,761,914,397			$1,809,000,000	$1,762,306,129	100.00%	6.044%
			Cost of LT Debt (includes annual expense from loss on reacquired debt)															6.065%

	Losses on Reacquired Debt	Issue Date	Reacquisition Date	Gross Proceeds	Total Gain/Loss to Amortize	Annual Expense
Y61181	13.50% FMB Due 10/1/12	19-Oct-82	25-Apr-88	$75,000,000	$8,989,952	$374,581
G21184	5.450% Colstrip 98B Fixed PCB due 04/30/33	1-May-03	1-May-09	$21,000,000	$411,622	$17,151
						$391,732

Footnote

1 On 7/1/98, the Trojan variable rates were fixed, although not extended.

2 $5.8 million in call premia resulting from acquisition of 9.46% and 7.75% issues was allocated evenly among August 2003 issues (see UE 180, PGE Exhibit 1400, page 3).

3 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 May 2006 issuances.

4 $5.1 million Trojan 1990B PCBs redeemed early in June 2007. Unamortized loss of $50,969 was added to the 5.80% series $170MM issued in May 2007 used to redeem the PCBs.

5 In February 2008, PGE repurchased the 5.279% issue due 04/01/2013. The issue was subsequentally reissued on 04/15/2008 at 4.45% for a period of 5 years (due on original maturity date of 04/01/2013).

6 "DD&E Issue Costs" (column J) was updated to reflect $222,000 discount to par at issuance.

7 "DD&E Issue Costs" (column J) was updated to reflect actual issuance expenses.

8 PCB issues put-back to PGE in May 2009. PGE re-marketed in March 2010 (due on original maturity date of 05/01/2033).

PGE Exhibit 1902

PGE Capital Structure Year-End 2005–2011

	Actual [1]					Forecast [2]	
	2005	2006	2007	2008	2009	2010	2011
Long-term debt [3]	879	937	1,313	1,164	1,558	1,809	1,709
Total shareholders' equity	1,197	1,224	1,316	1,354	1,542	1,594	1,957
LT Debt + Equity	2,076	2,161	2,629	2,518	3,100	3,403	3,666
LT Debt / LT Debt + Equity	42.3%	43.4%	49.9%	46.2%	50.3%	53.2%	46.6%
Equity / LT Debt + Equity	57.7%	56.6%	50.1%	53.8%	49.7%	46.8%	53.4%
Average Equity Ratio					53.6%	52.5%	52.6%
					52.6%	51.4%	51.7%
					51.2%	50.1%	50.8%
					51.2%	50.1%	50.9%
						48.3%	50.0%
							50.1%

Notes and Sources:
[1] PGE 10-K filings (provided in PGE's Response to OPUC Data Request No. 003)
[2] PGE Integrated Model (provided as work paper "Integrated Model 2008 to 2018(010910).xls" accompanying PGE Exhibit 100)
[3] Net of portion due within one year of year-end

UE 215 / PGE / 2000
Zepp

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Return on Equity

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Thomas M. Zepp

July 19, 2010

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Thomas M. Zepp and my business address is Utility Resources, Inc., 1500 Liberty Street, SE, Salem Oregon, 97302.

Q. Did you prepare direct testimony in this case?

A. Yes. I am responsible for PGE Exhibits 1200 – 1216.

Q. What is the purpose of this testimony?

A. Portland General Electric (PGE) asked me to review the June 4, 2010, opening testimonies, and exhibits to those testimonies, of OPUC Staff witness Steve Storm (Staff Exhibit 900) and ICNU-CUB witness Michael Gorman (ICNU-CUB Exhibit 200), and respond to their presentations where I thought appropriate. I was also asked to update PGE Exhibits 1205 through 1214, which presented my original discounted cash flow (DCF) and risk premium (RP) return on equity (ROE) estimates, and provide a new summary table equivalent to PGE Exhibit 1216.

Q. Would you please summarize your rebuttal testimony?

A. Yes. First, I provide updated ROE estimates for PGE. My updates indicate an average required ROE (RROE) for PGE of 11.27%. PGE Exhibit 2011 presents a summary of these updated DCF and RP analyses. The RROE resulting from my models is greater than the 10.50% requested by PGE.

Second, I address Mr. Storm's testimony. His ROE recommendation is based on just a single model (a multi-period DCF model). Mr. Storm incorrectly relies solely on dividend per share (DPS), rather than earnings per share (EPS), growth estimates in his short-term period. His reliance on low DPS growth estimates and intermediate- and long-term growth rates less than the forecast GDP growth rates results in an unreasonable ROE recommendation that is 70 basis points below the lowest ROE authorized by any commission for a vertically-integrated electric utility during the period 2005 to 2010. Mr. Storm repeatedly quotes Dr. Roger Morin in a manner that seems to lend credibility to his arguments; however, when the quotes are considered in their entirety, the positions of Dr. Morin actually oppose, rather than support, the points argued by Mr. Storm.

I also address Mr. Gorman's testimony. Mr. Gorman's analyses suffer from numerous flaws, including internal inconsistencies and calculation errors that render several of his reported results largely meaningless. His analyses lead to a recommended ROE that is 20 basis points below the lowest ROE authorized in the country since 2005. Mr. Gorman contends an additional 25 basis point ROE reduction should be adopted if PGE's proposed PCAM modifications are authorized, yet he provides no discussion of how PGE's PCAM actually compares with the mechanisms in place for the sample firms used to derive the ROE value on which his reduction is applied. A restatement of his analyses, to the extent possible, leads to an average ROE in excess of 10.5%, with no reduction for the proposed PCAM modifications.

In past cases the Oregon Commission has stated it will review ROEs authorized in other jurisdictions to help gauge the reasonableness of ROE recommendations. In sharp contrast to the recommendations of Staff and ICNU-CUB, the 10.5% ROE requested by PGE is less than 64% of the ROEs authorized for vertically-integrated electric utilities during the period 2005 to 2010 and thus is reasonable.

II. Updated ROE Estimates

Q. Please begin with the updates of your ROE estimates.

A. The updates of my ROE analyses are presented in PGE Exhibits 2001 through 2010 and are summarized in PGE Exhibit 2011. In making my updates I recognize that Allegheny Energy is currently seeking approval to merge with FirstEnergy and thus its stock price reflects investors' perceptions about the benefits of such a merger and about whether the utilities can obtain the requisite approvals from investors and regulators to proceed with the merger rather than the cost of equity. As a result, I do not include Allegheny Energy in my update. Due to the pending merger, Value Line has suspended its timeliness ranking for the utility as well.

Also, I have added UIL Holdings to my sample for purposes of my update to better enable the Commission to compare the differences in my equity cost estimates with those of Staff witness Storm. However, I do not agree that UIL Holding should be included in a sample used to determine benchmark cost of equity estimates for PGE for reasons I explain below.

Q. What are the results of your updates?

A. My updates indicate that PGE now has a cost of equity that falls in a range of 11.23% (an average of updates of my RP analyses) and 11.30% (an average of updates of the three DCF models I presented earlier in this proceeding). I also applied my analyses to Mr. Storm's sample and found an average of equity costs produced with the three versions of the DCF model I rely upon indicates a cost of equity for PGE of 11.6% (see PGE Exhibit 2011/2). Based on these updates and application of my methods to the sample relied upon by Mr. Storm, I found that every one of the equity cost estimates exceeded 11.0% and thus are substantially higher than the 10.5% ROE requested by PGE.

Q. Please describe PGE Exhibit 2001.

A. PGE Exhibit 2001 shows the current dividend yield for my expanded sample of benchmark electric utilities is 5.16%, slightly higher than the 5.10% average yield I found in PGE Exhibit 1205.

Q. Please describe PGE Exhibit 2002.

A. PGE Exhibit 2002 shows available updates of analysts' forecasts of growth for the 31 utilities. Averages of the growth rates reported by the four sources of financial information now fall in a range of 5.8% to 6.3% and have an overall average of 6.0%. These updated averages of growth rates are somewhat lower than they were at the time I prepared PGE Exhibit 1206.

Q. Please describe PGE Exhibits 2003, 2004, and 2005.

A. PGE Exhibit 2003/1 and PGE Exhibit 2005/1 are updates of PGE Exhibits 1207 and 1209. Based on these updates, these two versions of the DCF model indicate costs of equity for my benchmark sample of 11.2% at this time. PGE Exhibit 2003/2 and PGE Exhibit 2005/2 are estimates of the cost of equity made with those DCF models but for Mr. Storm's sample. Based on those DCF analyses, the indicated costs of equity are 11.5% and 11.4%, respectively, for Mr. Storm's sample. PGE Exhibit 2004 is an update of the range of the growth rates presented in PGE Exhibit 1208.

Q. Please describe PGE Exhibit 2006.

A. PGE Exhibit 2006/1 is an update of PGE Exhibit 1210. This version of the DCF model indicates the average cost of equity for my benchmark sample has declined from 11.2% to 11.0%. PGE Exhibit 2006/2 is the same DCF analysis but for Mr. Storm's sample. It indicates the cost of equity for Mr. Storm's sample is 11.2%.

Q. Did you update your forecasts of interest rates?

A. Yes. Based on averages of updated forecasts from Value Line, Blue Chip, and IHS Global Insight, the expected average cost of long-term Treasury bonds is now slightly higher and the cost of Baa bonds is slightly lower than when I prepared PGE Exhibit 1211 (see PGE Exhibit 2007).

Q. Have you updated PGE Exhibits 1212, 1213 and 1214?

A. Yes. I have updated those tables by including data for 2009. PGE Exhibit 2008 adds data for 2009 and deletes data for 1999 to maintain a ten-year period. PGE Exhibit 2009 adds data for 2009 and eliminates companies from the update that have cut dividends. PGE Exhibit 2010 updates PGE Exhibit 1214 by incorporating the more recent forecast of the Baa rate.

Q. Do you provide a summary of these updates in a table?

A. Yes, the summary is presented in PGE Exhibit 2011/1. With the new information, the three DCF estimates indicate that PGE's cost of equity falls in a range of 11.2% to 11.4% and has an average of 11.30%. The updated RP analyses indicate an equity cost range for PGE of 11.0% to 11.9% with an average of 11.23%. The overall average of equity cost estimates for PGE is 11.27%, 77 basis points higher than the 10.5% ROE requested by PGE. PGE Exhibit 2011/2 uses the updated data applied to Mr. Storm's sample. Using Mr. Storm's sample, the indicated cost of equity for PGE is 11.6% at this time.

III. Responses to Staff Witness Storm

A. Response to Mr. Storm's DCF Analysis

Q. Can you provide some perspective around Mr. Storm's recommended ROE of 9.2%?

A. Yes. PGE Exhibit 2012 is based on a compilation of authorized ROEs determined in 69 litigated cases for vertically-integrated electric utilities reported by Regulatory Research Associates (RRA) for the period 2005 to 2010.[1] These data put in perspective how harsh Mr. Storm's low recommendation is. His 9.2% recommended ROE is 141 basis points below the average of authorized ROEs found to be reasonable by various commissions throughout the country. The data in PGE Exhibit 2012 show that no commission found an ROE as low as 9.2% to be acceptable. The data underlying that exhibit also show that the lowest ROE authorized during the period 2005-2010 was 9.9%, 70 basis points above Mr. Storm's draconian recommendation.

In litigated cases, commissions examine various financial models and inputs to those models as well as the results of the models when they determine ROEs fair for both customers of utilities as well as the utilities. Even before details of Mr. Storm's DCF models are considered, this exceptionally low ROE raises serious questions about the models and assumptions Mr. Storm relied upon to produce such a low ROE estimate.

Q. How does the 10.5% ROE proposed by PGE compare to the data in PGE Exhibit 2012?

A. It provides a "gauge of reasonableness" that PGE's requested ROE is conservative and fair to ratepayers and investors. PGE's proposed ROE of 10.5% is 11 basis points below the

[1] Authorized ROEs for "electric delivery" companies that provide only transmission and distribution services are not included in the averages. To the extent that regulators allow those companies to automatically collect generation costs—or that such generation costs are billed and collected by the companies providing the generation—risks of generation are avoided and in a number of cases, regulators have provided lower authorized ROEs for such companies.

average of authorized ROEs during 2005-2010 of 10.61%. PGE's requested ROE is lower than the authorized ROEs found to be reasonable in 64% of the litigated cases during the period 2005-2010.

Q. Are you recommending that the Commission reject evidence provided by financial models and instead base PGE's authorized ROE on an average of ROEs adopted in other jurisdictions?

A. No, I am not. In Docket No. UE 116, the Commission addressed this issue and came to the following conclusion:

> We adhere to our prior determination that, while other ROE determinations may provide confirmation of a decision, they should not be used as an independent method on which to base an award…
>
> Accordingly, we will continue to review ROEs authorized in other jurisdictions to help gauge the reasonableness of the cost of equity estimates derived from independent methodologies. We will not, however, rely on such decisions as the basis for an ROE award for a utility. (Order No. 01-787 at page 34)

The evidence provided in PGE Exhibit 2012 is offered to "gauge the reasonableness" of Mr. Storm's cost of equity estimate, Mr. Gorman's 9.7% ROE recommendation, and PGE's requested ROE of 10.5%. These comparisons show that—even without an examination of the assumptions and models[2] used by Mr. Storm and Mr. Gorman (considered later in this testimony)—their recommended ROEs are unreasonable while PGE's request is right in line with what has been found to be reasonable in other litigated dockets.

Q. Do you have any other comments about the RRA data?

---

[2] I explain below that Mr. Storm has actually relied on only one version of the DCF model.

A. Yes. These data also corroborate the reasonableness of my updated average ROE estimate of 11.07% for the benchmark sample and 11.27% for PGE. This estimate of 11.07% falls within the range of authorized ROEs during 2005-2010 in which ten percent of those authorized ROEs were greater than 11.07%.

Q. At Staff Exhibit 900, pages 9-11, Mr. Storm argues that investors in electric utilities must require an ROE less than the 10.7% historical average market return because those companies are less risky than average stocks. Do you have a response?

A. Yes. This 10.7% annual return for the S&P 500 is a geometric annual average return. In at least twelve places in his testimony, Mr. Storm appeals to Roger Morin and Brealey and Meyers as authorities regarding cost of equity estimates. I have attached Appendix 4-A from Professor Morin's 2006 book, <u>New Regulatory Finance</u>, as PGE Exhibit 2021 to explain why the 10.7% return is based on an incorrect concept and thus the 10.7% realized ROE provides an inadequate measure of investors' required returns. In this appendix, Professor Morin includes an excellent example by Brealey and Meyers, an explanation provided by Morningstar in numerous editions of the Ibbotson SBBI Yearbook, and Morin's own clear explanation of why it is <u>arithmetic</u>, not geometric, annual average returns that are relevant when considering discount rates, and thus RROE, for investors.

The scholarly discussion in PGE Exhibit 2021 explains that because common stocks are risky, returns on those stocks vary from year to year. If one believes the past is prologue for the future, the geometric annual average return of 10.7% will understate the return required by investors because it fails to recognize the past variability in stock returns. The arithmetic annual average return of 12.56%—or Ibbotson and Chen's approximation of 12.63% (found at Staff Exhibit 902, page 16)—is required to account for that variability.

Additionally, Mr. Storm takes the 10.7% return out of context. Ibbotson and Chen specifically state that, “[l]ater in the paper when we do our forecasts, we convert geometric average returns to arithmetic average returns” (Staff Exhibit 902, page 5). At the time Staff Exhibit 902 was written, the historical arithmetic annual average return and standard deviation in returns reported by Ibbotson and Chen were 12.56% and 19.67%, respectively (Staff Exhibit 902, page 5). At Staff Exhibit 902, page 16, the authors Mr. Storm relies upon state the geometric return needs to be adjusted upward by 1.93% to reflect the fact that there is variance in those market returns.

Q. Does Staff Exhibit 902 provide support for a cap on RROEs for electric utilities of 10.7%?

A. No, it does not. To the extent that Staff Exhibit 902 should be relied upon to set such a cap, the cap is 12.63%—not 10.7% (Staff Exhibit 902, page 16).

Q. Turn to Staff Exhibit 900, pages 11-12. Mr. Storm included UIL Holdings in his sample. In Section II, you stated that you do not agree that UIL Holdings should be included in a sample used to determine benchmark estimate of the cost of equity for PGE. What are your reasons?

A. UIL Holdings is the parent of an “electric delivery company” which provides only distribution and transmission services and thus does not have the risk of a vertically-integrated utility such as PGE. UIL is adding some electric peaking capacity, but is also in the process of attempting to acquire three gas utility subsidiaries of Iberdrola for $1.3 billion, a value greater than UIL Holding’s current market capitalization of $875 million. Investors may have priced UIL shares based on concerns with current or future mergers and not the risk of an electric utility. But, because Mr. Storm includes UIL in his analysis, I have added it to the sample used for my updates in order to facilitate comparisons.

Q. At Staff Exhibit 900, page 12, Mr. Storm states he has used two models to develop Staff's recommended ROE. Do you have any comments about this statement?

A. Yes, I have two comments. First, Mr. Storm actually used only one DCF approach, though he claims to have used two different multistage DCF models. Both models rely on the same average market prices for stocks in his sample, the same dividends per share estimates for 2010 to 2015, and the same annual rate of GDP growth for the period 2016 to 2020. But contrary to his testimony at Staff Exhibit 900, page 16, his third stages should produce the same result if they were computed correctly; I discuss this further below.

Second, at pages 19, 51, 54, 69 and other places in Staff Exhibit 900, Mr. Storm appeals to a book authored by Roger Morin, who is an expert on cost of equity estimation. Professor Morin tells us:

> It is dangerous and inappropriate to rely on only one methodology in determining the cost of equity. The results from only one method are likely to contain a high degree of measurement error. The regulators hands should not be bound to one methodology of estimating equity costs…
>
> When measuring equity costs, which essentially deal with the measurement of investor expectations, no single method provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology… It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity. (Roger Morin, New Regulatory Finance, 2006, page 28)

Mr. Storm not only limited his equity cost analysis to one method—the DCF method—but also only looked at results for one version of the model and a limited set of assumptions about how investors determine growth. Given this limited approach, as Professor Morin pointed out in the quotation above, Mr. Storm's approach is likely to contain a high degree of measurement error.

Q. You noted Mr. Storm relies on Dr. Morin as an authority. Does Dr. Morin apply multiple methods when he determines cost of equity?

A. Yes, he does. In 2008 testimony in Nevada, he determined cost of equity estimates with four versions of the risk premium approach and four versions of the DCF model (Pre-filed direct testimony of Roger Morin, Nevada Power Company, Docket No. 08-12002). In 2009 testimony filed by Dr. Morin in New York for Consolidated Edison (CECONY) (Case No. 09-E-0428), Dr. Morin conducted three risk premium analyses and four DCF analyses to determine benchmark equity cost estimates for CECONY. Subsequently, he noted that there is uncertainty and turmoil in current financial markets, and combined these estimates with his judgment to recommend the New York Commission set CECONY's authorized ROE in the upper half of his recommended ROE range.

Q. At Staff Exhibit 900, page 64, lines 11-12, Mr. Storm states that he obtained different internal rates of return estimates of 8.8% and 8.9% by using his two versions of the DCF model. Does this indicate a problem in the analysis?

A. Yes. This finding shows there is something wrong with the spreadsheets he is using to estimate his cost of equity. As I discussed above, he should always get the same internal rate of return. Equations (3) and (4) of PGE Exhibit 1200, page 20, show why this is true. One of Mr. Storm's models is conceptually an application of equation (3) presented in my direct testimony while the other model is conceptually an application of equation (4). As I explained in my direct testimony, if applied correctly, both equations (3) and (4) would produce the same result if inputs and samples are the same. Based on his statement at page 64, the error is not significant, but there is an error which is related to his calculation of the terminal value in his forty-year version of the model.

Q. Did you correct the error and re-run his analysis?

A. No. Essentially, PGE Exhibit 2006 (and in direct testimony PGE Exhibit 1210) is the same DCF model Mr. Storm relies upon and thus I considered internal rates of return for his sample computed with PGE Exhibit 2006/3 to provide estimates of internal rates of return. This analysis uses prices he adopted, Mr. Storm's DPS values for 2010 and 2011, Value Line EPS forecasts for 2012-2015, and my assumed growth in GDP for the final stages. PGE Exhibit 2006/3 produces higher rates of return because it uses Value Line forecasts of EPS instead of DPS growth for 2012 to 2015, then assumes my estimates of future GDP growth for the years 2016 and beyond. With those changes in assumptions, the equivalent of his model indicates the average cost of equity for his sample is 10.7%.

Q. Why are your estimates in PGE Exhibit 2006/2 and PGE Exhibit 2006/3 different?

A. They are different because:

(1) I use the average prices for April-June 2010 in PGE Exhibit 2006/2 instead of Mr. Storm's average prices which are used in PGE Exhibit 2006/3,

(2) I recognize the time value of money when I compute the first dividend in PGE Exhibit 2006/2, and

(3) I assume investors rely on an average of analysts' forecasts of growth one year sooner in PGE Exhibit 2006/2 than in PGE Exhibit 2006/3.

Q. Have you determined the primary reasons Mr. Storm's estimates of the cost of equity are so much lower than yours?

A. Yes, I have identified four primary reasons:

- First, he assumes investors expect growth of roughly 3.78% during the period 2010 to 2015 when analysts expect EPS growth will be much higher.
- Second, he adopts a conservative estimate of future GDP growth to populate his second (2016-2020) stage, which is much lower than the actual annual average growth of 6.7% in GDP that occurred between 1930 and 2008, and which is also lower than Value Line's June 18, 2010, forecast of GDP growth of 5.47% for 2013-2015 [(1.034 x 1.02) - 1].
- Third, he reduces his conservative estimates of GDP growth during both time periods beyond 2015 to account for his contention that it is unreasonable to assume electric utilities will grow as rapidly as the rest of the economy.
- Fourth, while he does not challenge the logic of adjusting dividend yields for the time value of money, he fails to make such an adjustment. He estimates that not adjusting for the time value of money reduces equity cost estimates by 20 basis points (Staff Exhibit 900, page 66).

Q. How does Mr. Storm justify an initial growth rate as low as 3.78%?

A. He justifies such a low growth rate by appealing to a quotation from page 284 of Professor Morin's 2006 book, New Regulatory Finance. That quotation is, "DCF theory states clearly that it is the expected future cash flows in the form of dividends that constitute investment value." Based on that appeal to an authority, Mr. Storm relies exclusively on DPS growth rates forecasted by Value Line to determine growth rates for his initial stage. He gives zero weight to any other growth rates projected by Value Line and no weight to forecasts of growth made by other financial institutions.

Q. Does Dr. Morin actually support the exclusive use of Value Line DPS forecasts as is suggested by the citation?

A. No, he does not. First, Mr. Storm uses the quotation out of context. The full quotation is as follows:

> DCF theory states clearly that it is the expected future cash flows in the form of dividends that constitute investment value.
>
> However, since the ability to pay dividends stems from a company's ability to generate earnings, growth in earnings per share can be expected to strongly influence the market's dividend growth expectations. After all, dividend growth can only be sustained if there is growth in earnings. (Roger Morin, New Regulatory Finance, 2006, page 284)

Contrary to Mr. Storm's contention, Dr. Morin does not provide support to his decision to rely only on DPS forecasts to determine the best available estimates of growth expected by investors during 2010 to 2015. Also, limiting forecasts in his initial period to Value Line forecasts of DPS growth is inefficient. It ignores valuable information available to investors that is contained in other Value Line forecasts. More importantly, it ignores information in analysts' forecasts of growth that are widely relied upon by investors.

Q. Above you cited two recent testimonies presented by Dr. Morin in regulatory proceedings. Did Dr. Morin give any weight to DPS forecasts when he actually applied the DCF model?

A. No, he did not. In both cases he relied exclusively on analysts' forecasts of EPS growth provided by Value Line and by Zacks for two different samples of electric utilities to conduct his four DCF analyses. In the 2009 New York case, he answered the following question about the use of DPS forecasts in his pre-filed testimony:

> Q. Did you consider dividend growth in applying the DCF model?

> A. No, not at this time. This is because it is widely expected that some utilities will continue to lower their dividend payout ratio over the next several years in response to heightened business risk and the need to fund very large construction programs over the next decade…
>
> As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations.

He then went on to say:

> Moreover, as a practical matter, while earnings growth forecasts are widely available, there are very few dividend growth forecasts. (Pre-filed testimony of Roger A. Morin, Case No. 09-E-0428, pages 39-40)

Q. Have you restated Mr. Storm's analysis to recognize expected EPS growth as well as DPS growth?

A. Yes. Mr. Storm estimates the average DCF cost of equity for his sample to be 8.9% prior to adjusting that estimate for differences in leverage he attributes to PGE and his sample. In making my restatements of growth during the period 2010 to 2015, I assume investors might rely on Value Line's forecasts of DPS growth in 2010 and 2011, but would look to EPS growth forecasted by Value Line for the other years during this initial period. Mr. Storm relies on Dr. Morin as an expert. As explained above, Morin states he expects investors to give no weight to DPS forecasts at this time and instead rely on EPS forecasts. Value Line forecasts DPS growth will be less than EPS growth during 2010-2015. Thus, the restatement I have made is a conservative estimate of initial growth expected by investors. With this restatement and no changes in the long-term growth forecasts that Mr. Storm adopts in his model, the indicated cost of equity for his sample increases by 40 basis points (see PGE Exhibit 2013).

Q. Please turn to the second issue you have identified. Do you agree that investors expect long-term growth for electric utilities to be less than GDP growth?

A. No, I do not. I addressed this issue in PGE's last general rate case, Docket No. UE 197. I pointed out that Value Line had 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, page 157, December 1, 2006). Such a situation is consistent with growth for electric utilities being the same or higher than GDP growth. Also, 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."

PGE Exhibit 2014 shows that as the factors mentioned by Value Line were recognized by the investment community, analysts' forecasts of growth for that sample increased from 4.8% in 2004 and 5.3% in 2005 to 6.0% in 2006 and 7.0% in 2007. While analysts currently expect somewhat slower growth than in 2007, growth is still expected to be higher than in 2004 and 2005. The EIA report relied upon by Mr. Storm to justify slower growth for electric utilities is inconsistent with Dr. Morin's comments reported above and information provided by Value Line to investors. The important point is what growth is expected by investors, not what growth is being forecasted by EIA or another government agency.

Q. Have you revised Mr. Storm's analysis to reflect longer-term growth for his electric utilities sample that is equal to his estimates of GDP growth?

A. Yes, I have. In making this restatement I have accepted the GDP growth rates relied upon by Mr. Storm in his analysis but have assumed electric utilities will grow at the same rates as his forecasts of GDP growth of 4.75% during 2016-2020 and 5.86% during all years after 2020. Support for the conservative nature of the 4.75% forecast is provided by Value Line's June 18, 2010, forecast of GDP growth of 5.47% for 2013-2015. Support for his 5.86% GDP forecast is provided at Staff Exhibit 900, pages 29-31. The 5.86% growth rate is a conservative estimate of future long-term average annual arithmetic GDP growth because it is based on a geometric annual average real GDP forecast.

Q. What is the impact of these changes?

A. These changes increase the indicated cost of equity from 9.3% to 10.5% (see PGE Exhibit 2015).

Q. Do you have any concerns with the GDP growth rates Mr. Storm has relied upon?

A. Yes. PGE Exhibit 2021 explains why arithmetic annual average returns should be relied upon to determine required risk premiums and future RROEs if one believes the past is prologue for the future. Unless arithmetic annual returns are used to make such determinations, past geometric annual averages are not achievable because returns will vary from year to year. The same logic applies when determining GDP growth rates from historical data because GDP growth will vary from year to year. Because most of the growth rates included in Mr. Storm's considerations are such geometric annual average growth rates, averages of such growth rates will understate the growth in GDP required to match past history.

Second, although he has included real and nominal GDP data for long periods in the tabs of his spreadsheet analysis, he does not rely on such data to determine one or more estimates of projected GDP growth. I explain in my direct testimony why such long-term average GDP growth should be considered in a DCF model that presumably discounts growing future cash flows for a very long period into the future. To be consistent with my restatement of his analyses, however, I do not substitute GDP growth I consider more appropriate for the growth rates he presented.

Q. At Staff Exhibit 900, page 65, Mr. Storm appears to agree that it is appropriate to adjust dividends upward by just enough to offset the time value of money. Did he adjust dividends upwards in his analyses?

A. No. At pages 66-67 he removes the impact of adjusting for the time value of money, apparently because he correctly recognized that all of the cash flows were adjusted upward to reflect the time value of money. He apparently did not consider that his model assumes that each of the annual cash flows are assumed to be paid at the end of each future year and thus this adjustment is appropriate in his model as well. The stock prices are higher because investors get those cash flows on a quarterly basis. The adjustment for the time value of money is required to match this information about prices paid for stocks with the model he is using to compute his internal rates of return.

Q. What is the restated value of Mr. Storm's equity cost estimate once the time value of money is recognized?

A. It is 10.7%. As I noted previously, Mr. Storm determined that recognizing the time value of money increases the dividend yield and cost of equity by 20 basis points (see Staff Exhibit 900, page 66). I have used his estimate in preparing PGE Exhibit 2015.

Q. Does Mr. Storm provide any reason not to adjust the cost of equity to reflect the time value of money?

A. No.

Q. As a final adjustment, Mr. Storm adjusts his estimate of PGE's cost of equity for differences in leverage he attributes to PGE and the sample. Do you agree with that adjustment?

A. No. Mr. Hager and Mr. Valach explain that some ratings agencies impute debt based on PGE's purchased power contracts and operating leases (PGE Exhibit 1100, page 26). Standard & Poor's method, for example, adds more than 2.2% of additional debt to PGE's capital structure to reflect such an imputation. Once imputed debt is recognized, if an adjustment to the cost of equity for leverage should be made, PGE's cost of equity should be increased, not decreased.

Q. Does Mr. Storm offer persuasive rebuttal to your conclusion that PGE requires an ROE that is 20 basis points higher than the average cost of equity for your benchmark sample?

A. No, he does not.

Q. What is the important conclusion you draw from your examination and restatement of Mr. Storm's DCF estimate of the cost of equity for PGE?

A. I conclude a reasonable restatement of the inputs to his model and an update of his analysis indicates PGE has a cost of equity that is no less than 10.5%, the ROE requested by PGE. See PGE Exhibit 2015. If that estimate is revised to recognize the time value of money it increases to 10.7% and further increases to 10.9% if the company-specific risk adder I recommended is recognized. Additional support for PGE having an RROE above 10.5% is that an update of my DCF models using his sample indicates a DCF equity cost range of 11.4% to 11.7%.

B. Response to Mr. Storm's Critiques of PGE's DCF Analyses

Q. How do you respond to his criticism regarding your use of analysts' forecasts of growth (Staff Exhibit 900, pages 49-51)?

A. I have two responses. First, Mr. Storm is inconsistent by criticizing analysts' forecasts because they may be made by analysts working at sell-side firms (Staff Exhibit 900, page 49, line 12) but he then endorses Value Line forecasts, which are not. The inconsistency arises because the average of the analysts' forecasts of growth of 6.4% was not much different than the average of comparable estimates being made by Value Line of 6.1%. Moreover, an average of EPS growth estimates made by Value Line is currently the same as the average of analysts' growth rates (see PGE Exhibit 2002/1).

Second, he offers a journal article to support his claim of potential bias in analysts' forecasts (Staff Exhibit 900, page 50 and Staff Exhibit 918). I have seen this criticism many times over the years. It is generally a criticism of the quality of analysts' forecasts for non-regulated companies, not regulated utilities. Obviously, it is more difficult to forecast growth and earnings for such non-regulated companies than for electric or gas utilities. The criticism also fails to recognize that alternatives—such as historic growth—are even poorer predictors of the future. Analysts take the past into account as well as anticipated differences in the future and the past when they make forecasts.

Q. Have you conducted any studies of the quality of analysts' forecasts for utilities?

A. Yes. I have conducted analyses of the quality of forecasts for gas and electric utilities and found that, contrary to Mr. Storm's contention, once differences in expected and realized inflation are taken into account, analysts' forecasts are very accurate. PGE Exhibit 2016 is an example of such past analyses. It was presented to this Commission in Docket No. UG 132 and thus is available to Staff.

Q. What is your third response?

A. My third response is that the quality of the analysts' forecasts is not the real issue. Since investors rely upon such forecasts, stock prices and equity cost estimates depend on such forecasts—a point that apparently is overlooked by Mr. Storm.

Q. Finally, at Staff Exhibit 900, page 51, Mr. Storm offers a quotation from Roger Morin that he contends provides support for giving no weight to analysts' forecasts. Do you have a response?

A. Yes. As discussed above, Professor Morin used Value Line forecasts and analysts' forecasts reported by Zacks to conduct the DCF analyses he presented in rate cases in Nevada and New York. Dr. Morin does not agree with Mr. Storm.

Q. At Staff Exhibit 900, page 53, lines 9-11, as another criticism of reliance on EPS growth rates, Mr. Storm claims "the estimated growth rate in earnings used by PGE includes a certain amount of 'bounce,' as recovery from the recession continues." Do you agree?

A. No, his contention is factually incorrect. PGE Exhibit 2014 combines my updated analysts' forecasts from PGE Exhibit 2002 with a table of analysts' forecasts I presented in UE 197. These data show that prior to the recession, the average of analysts' forecasts was 7.0%, an average that is higher than the current average of analysts' forecasts for this sample of 6.0% and higher than the 6.4% average for the sample of 31 utilities I used to prepare my direct testimony. Mr. Storm's claim of a "bounce" is not supported by the facts and should be disregarded.

Q. At Staff Exhibit 900, page 53, line 19, Mr. Storm again cites the quotation from Dr. Morin. Do you have a response?

A. Yes. Here again, Mr. Storm takes the quotation from Dr. Morin's book out of context. The next paragraph in Morin's book indicates one should expect investors to look to EPS growth. Morin says "It is the expectation of earnings growth that is the principal driver of stock prices". (Morin, New Regulatory Finance, page 284)

Q. At Staff Exhibit 900, page 55, Mr. Storm recommends the Commission not consider results of your constant growth DCF model. Do you have a response?

A. Yes. As stated before, neither Mr. Storm, Mr. Gorman, nor I know exactly what information investors consider when they determine the growth rates in the DCF model or what model investors use to price stocks. The constant growth DCF model is frequently found in the financial literature and is often presented by parties working for regulatory staffs as well as utilities in regulated proceedings. Mr. Storm has no basis to assume his model is preferred by investors or that the constant growth DCF model is not the one primarily relied upon by investors. I urge the Commissioners to consider the results of my constant growth DCF model along with all of the other equity cost estimates I have presented when it applies its judgment to determine the cost of equity that PGE faces.

Q. At Staff Exhibit 900, pages 56-58, Mr. Storm claims the FERC two-step model is just another constant growth DCF model. Do you agree?

A. No. The FERC model is certainly not a constant growth model. It is instead a model used to approximate the results of multi-stage DCF models FERC found to be reasonable. Giving a weight of two-thirds to initial estimates of growth rates and a one-third weight to the final estimate of GDP growth provided a simple approximation of the results that would be obtained with more complicated models, such as the one proposed by Mr. Storm.

Q. At Staff Exhibit 900, page 60, Mr. Storm objects to you using EPS forecasts of growth as measures of the short-term growth rates in the type of model used by FERC because they are not DPS growth rates. Do you have a response?

A. Yes. My response is that I did what FERC does. FERC wisely uses analysts' forecasts of EPS growth as is done by Dr. Morin, the authority to which Mr. Storm appeals at least eleven times in his testimony. FERC and Dr. Morin correctly recognize that investors would look at EPS growth because such forecasts are widely available and provide the support needed for growth in dividends. Mr. Storm fails to look at growth rates that would be utilized by investors when (and if) they applied the DCF model to price stocks.

Q. At Staff Exhibit 900, pages 60-62, Mr. Storm outlines his criticisms of the sources you have used to determine your estimate of long-term GDP growth. Do you have a response?

A. Yes. My estimate of future GDP growth is based on an average of a current forecast of near-term GDP growth and recognition of GDP growth that occurred in the past. I strongly disagree with Mr. Storm's decision to give zero weight to the long-term GDP forecast I considered in formulating my estimate of future long-term GDP growth (after an adjustment for expected differences in inflation). Mr. Storm considers past GDP growth but limits his consideration to historical data that started in 1980. My data extend back to 1930. His GDP forecasts do not appear to take into account the wealth of knowledge provided by the growth that the U.S. economy has actually experienced and may experience again. The longer period I considered in formulating my forecast of GDP growth should be accounted for when one considers what might happen out 150 years into the future. This past history is information available to investors. By ignoring it, Mr. Storm biases downward a reasonable estimate of long-term GDP growth (required by his DCF model) that may occur in the U. S.

Q. At Staff Exhibit 900, page 62, Mr. Storm states that there are inherent limitations in the DCF model you presented in PGE Exhibit 1209. Do you have a response?

A. Yes. FERC does not think there are "inherent limitations" in this model and neither do I. This is one more version of the DCF model that investors might consider when they price electric utility stocks and should be considered by the Commission.

Q. At Staff Exhibit 900, page 69, Mr. Storm again appeals to Morin as an authority to justify relying on only DPS forecast in the initial stage of his model. Do you have a response?

A. Yes. As stated before, this quotation from Dr. Morin is taken out of context and is in conflict with the methods Dr. Morin actually applies to estimate equity costs with the DCF model. Dr. Morin does not support him. Limiting forecasts in his initial period to Value Line forecasts of DPS growth is inefficient. It ignores valuable information available to investors that is contained in other Value Line forecasts. It also ignores information contained in analysts' forecasts of EPS growth which are widely relied upon by investors.

C. Response to Mr. Storm's Critiques of PGE's Risk Premium Analyses

Q. Please turn to Mr. Storm's comments about your risk premium approaches. Are risk premium approaches useful and widely used?

A. Yes, they are. Professor Morin—the authority cited numerous times by Mr. Storm—states that the risk premium approach is useful and widely used:

> The risk premium approach to estimating the cost of equity derives its <u>usefulness</u> from the simple fact that while equity return requirements cannot be readily quantified at any given time, the return on bonds can be assessed at

every instant in time. If the magnitude of the risk premium between stocks and bonds is known, then this information can be used…

Risk premium analyses are widely used by analysts, investors, and expert witnesses and are widespread in investment community reports. (Morin, New Regulatory Finance, page 108, emphasis added)

Q. Does Mr. Storm offer a risk premium analysis for the Commission's consideration?

A. No. Mr. Storm limits the information he provides to the Commission to one single cost of equity model, his version of the DCF model.

Q. Please start with your response to his criticism of PGE Exhibit 1214. At PGE Exhibit 900, page 80, Mr. Storm says there are two "flaws" in your risk premium analysis and presumably Dr. Morin's risk premium analysis that is similar to yours. Please respond.

A. The first "flaw" he contends, in both my analysis and the one presented by Dr. Morin in his book, is that Dr. Morin and I have used the same set of values—those for the bond rate—on both sides of the regression model. Mr. Storm, by adopting Staff witness Conway's testimony in UE 180, contends that having the bond rate on both sides of the equation creates circular reasoning in that the results appear to show a high degree of statistical significance that is really the result of having the same interest rate on both sides of the equation (Staff Exhibit 900, page 82). Mr. Storm is wrong, as was Mr. Conway in UE 180.

I used the following formula in my analysis:

Risk premium = A_0 + (A_1 x Baa bond rate),

where the risk premium is defined as the authorized ROE (AROE) minus the Baa rate, and A_0 and A_1 are estimated coefficients from a regression analysis. Based on theory and empirical studies I discussed at PGE Exhibit 1200, pages 28-30 and 33-35, A_1 is expected to be negative and fall between the values of 0 and -1. In fact, the regression analysis reported in PGE Exhibit 1214 shows the estimated value for $A_1 = -.3931$ is both statistically less than zero and greater than -1 (i.e. between 0 and -1). In words, this regression result tells us risk premiums vary inversely with changes in the Baa rate.

Alternatively, I could have recognized that costs of equity are expected to move in the same direction as interest rates, but by less. In that formulation of the analysis, the model to be estimated would be:

$$\text{AROE} \quad = \quad A_0 \quad + \quad (B_1 \text{ x Baa bond rate}),$$

where B_1 is expected to be equal to $(1 + A_1)$. Mathematically, $(1 + A_1)$ is expected to be +.6069 (i.e., 1 - .3931) and B_1 is expected to be statistically significantly less than +1.0 and statistically significantly greater than zero. Presumably this version of the model would not be subject to the "circularity flaw" that Mr. Storm contends impacts results of Dr. Morin's published model and my model.

Q. Did you run a regression using this alternative version of the model?

A. Yes.

Q. What were the results of that analysis?

A. The results are as follows:

A_0 (the constant or intercept term) = .06522

B_1 (the slope term) = .6069

As expected, the estimated slope in the alternative version of the model was found to be equal to that in my previous regression (1-.3931) and it is statistically significantly less than +1.0 and statistically significantly greater than zero.

Q. Staff implies that including the interest rate on both sides of the equation in the analysis presented in PGE Exhibit 1214 somehow creates a result that appears to show a high degree of statistical significance that is not merited. Do you have a response?

A. That bold claim is unsupported. In the analyses in both PGE Exhibit 1214 and the alternative versions presented here, standard errors of the estimated slope coefficients and intercept terms are identical. The dependent variables in PGE Exhibit 1214 and the alternative version of the model presented above have different dependent variables and thus a comparison of R^2 values is a questionable exercise. But to the extent that Mr. Storm believes the estimate of the R^2 in PGE Exhibit 1214 was enhanced by having the interest rate on both sides of the equation, the claim is not supported by the statistical results. The R^2 value for the alternative formulation of the model is .768 while it was .581 in PGE Exhibit 1214.

Q. Could Mr. Storm have run the regression analysis you present here?

A. Yes. In response to ICNU-CUB data requests, PGE provided these data in electronic form and the source documents that contained these data. After reading Mr. Storm's testimony, I ran the alternative regression discussed above with the data that PGE had provided. He could have done the same thing. If he had, he would know this "flaw" is not an issue. Claiming this first "flaw" appears to be an attempt to muddle up the record and cast doubt on a model that Dr. Morin and I both consider to be useful.

Q. What is the second "flaw" he says he has identified?

A. The second "flaw" is that the proxies for costs of equity are authorized ROEs found by various commissions in litigated cases. While I agree with the Oregon Commission that such data provide a gauge to determine the reasonableness of estimates of the cost of equity, I do not agree that the use of the data I use in PGE Exhibit 1214 creates a "flaw."

In litigated cases, various parties estimate costs of equity with DCF, RP, and other financial models, and the commissioners in those jurisdictions ultimately determine what costs of equity are revealed by those models. All commissions have responsibilities to ratepayers and utilities, and ultimately face the possibility of being held accountable for their determinations by the U.S. Supreme Court. As a result, litigated decisions provide useful—though not the only—proxies for costs of equity at different points in time.

Professor Morin addresses the use of allowed risk premiums in Section 4.5 of <u>New Regulatory Finance</u> at pages 123-125. He notes that it is sometimes alleged that reliance on allowed risk premiums is circular. He says that, “[t]his is a dubious argument to the extent that allowed risk premiums are presumably based on objective market data (dividends, interest rates, betas, stock prices, etc.) and not strictly on decisions of other regulators.” Morin also agrees with past Oregon Commission decisions when he states that sole reliance on decisions of other commissions would indeed be circular if the only data relied upon were those other decisions. Morin does, however, conclude that, “[a]llowed risk premiums are presumably based on the results of market-based methodologies presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive market place.”

In past orders, the Oregon Commission has stated that it will use decisions from other commissions “to gauge the reasonableness of their decisions.” PGE Exhibit 1214 provides a basis to judge the reasonableness of Mr. Storm’s low equity cost estimate of 9.2%, Mr. Gorman’s low recommended equity cost of 9.7%, and PGE’s proposed ROE of 10.5%. To the extent PGE 1214 and PGE Exhibit 2010 are used to gauge the reasonableness of PGE’s requested ROE of 10.5%, they show such a request is reasonable and Mr. Storm’s recommendation of 9.2% and Mr. Gorman's recommended ROE of 9.7% should be given no weight.

Q. Do you have a response to Figure 8 and Mr. Storm's discussion of that figure at Staff Exhibit 900, pages 84-85?

A. Yes. The argument he presented in Figure 8 and at Staff Exhibit 900, pages 84-85, is basically the same argument he presented to respond to the risk premium analysis I presented in PGE Exhibit 1213. At page 78, line 13, Mr. Storm notes that the regression result of total returns on Baa bond returns resulted in an R^2 coefficient of .0422. This result was not unexpected for at least three reasons:

(1) an analyst should expect relatively low R^2 values when attempting to explain actual market returns (I found that to be the case when I worked at the Oregon PUC and conducted numerous statistical studies designed to evaluate methods used to estimate equity costs for utilities),

(2) actual returns in any year are not expected to be good indicators of costs of equity even though an average of those returns over a long period are good indicators (see PGE Exhibit 1200, page 32), and

(3) a part of the change in annual actual returns for Moody's utility index can be attributed to changes in actual market returns, thus an analysis like the one presented by Mr. Storm suffers from an "omitted variable problem" (i.e., a well-known explanatory variable has not been included in the analysis). Presumably, the appropriate relationship would be:

Total actual returns = f (interest rates, market return).

Instead, Mr. Storm assumes:

Total actual returns = f (interest rates alone).

The analyses presented in Figure 7 and Figure 8 suffer from this same problem. In both analyses, Mr. Storm has relied only upon interest rates—albeit in the case of Figure 8, a constant slope times those interest rates and a constant intercept term—to predict actual returns for utility stocks. Both analyses fail to recognize that a portion of the change in actual total utility returns is the result of changes in market returns and low R^2 values are not unexpected.

Finally, whether we examine the analysis in PGE Exhibit 1214 or the alternative analysis discussed above (in which costs of equity—instead of risk premiums—are tied to interest rates), PGE Exhibit 1214 shows the estimated relationship is highly significant, very stable, and provides good forecasts of the variable of concern—the cost of equity underlying those actual market returns. Contrary to his statement at Staff Exhibit 900, page 85, line 6, PGE's third risk premium analysis explains well and generally forecasts well.

Q. Turn to his other criticisms of your risk premium analyses. At Staff Exhibit 900, page 74, he updates the risk premium analysis you presented in PGE Exhibit 1212. Is his update reasonably accurate?

A. Yes. I updated that analysis in PGE Exhibit 2008 and found the average risk premiums for the most recent ten-year and five-year periods were close to the values he reports at page 74. He also found the update of my RP method indicates an ROE for my benchmark sample that falls in a range of 10.8% to 11.0%.

Q. At page 75, he criticizes your analysis in PGE Exhibit 1212 claiming that useful predictions of a security's future return requires some stability in the value of the risk premium. Do you have a response?

A. Yes. Apparently, Mr. Storm does not recognize that the data he provides confirm that there is such "stability." He finds that the correlation between the proxies for costs of equity (in this case realized book returns) and bond rates chosen for the analysis is positive. Obviously, there will not be a "perfect" correlation because the proxies for costs of equity are not precise measures of equity costs and the timing differences between dates when prices for utility services for the various utilities in the sample were set and average annual bond rates used in the analysis probably differ from utility to utility. The correlation is, however, positive and thus his own analysis indicates a reasonable level of "stability." If that correlation is "small," that is not unexpected when dealing with book returns that have huge variances from year to year. Upon reflection, it is partly because of the annual variances in book returns and market returns that investors require higher ROEs for utilities than for government bonds. Figure 6, which Mr. Storm presents at page 76, is exactly what one should expect it to be when realized book equity returns or realized market returns are expected to be uncertain.

Q. Please turn to his criticism of the risk premium approach presented in PGE Exhibit 1213.

A. In this analysis, he also finds a positive correlation between the proxies for costs of equity and Baa bond rates but a very low R^2 when he ran a regression of total returns on Baa bond rates. Above I explained why his omission of market returns in such an analysis would lead one to expect a low R^2 and the results in Figure 7. I do not repeat that testimony again.

Q. Did Mr. Storm address your explanation of PGE Exhibit 1213 provided at PGE Exhibit 1200, page 32?

A. No. At PGE Exhibit 1200, page 32, lines 4-7, I explained that, "[t]his 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." He never explains why the Commission should not consider such a long-term average to be a useful measure of the risk premium required by investors.

Q. Please put his criticisms of your RP estimates in perspective.

A. For perspective, the question of importance is whether a consideration of the data provided by my DCF and RP analyses provides a better indication of the cost of equity for electric utilities than the equity cost he determines with his version of the DCF model populated with his carefully chosen assumptions. Mr. Storm, Mr. Gorman, and I do not know what models are used by investors to price utility stocks and—with respect to the DCF model—how investors determine growth rates. It is because we do not know the best way to estimate risk premiums—and for that matter DCF equity costs—that I recommend the Commission consider more than one method. The risk premium approaches I present make alternative assumptions about the best way to determine a relevant risk premium. Mr. Storm offers no risk premium analysis and offers no basis to revise my risk premium analyses and thus his comments should be disregarded.

IV. Responses to ICNU-CUB Witness Gorman

Q. Please turn to your responses to Mr. Gorman. What are the equity cost estimates he relies upon in this case?

A. Mr. Gorman relies on three DCF estimates summarized in his Table 5 (ICNU-CUB Exhibit 200, page 35) that produce an average cost of equity of 10.12% and two CAPM estimates that have an average of 9.5% (ICNU-CUB Exhibit 200, page 46). He also presented a risk premium analysis, but states that he only relies on it as a reasonableness check (ICNU-CUB Exhibit 200, page 41). Based on an average of his DCF and CAPM results he finds a midpoint ROE estimate of 9.8% which he subsequently reduces by 10 basis points to his recommend ROE for PGE of 9.7%. I summarize the means and medians of Mr. Gorman's estimates and my restatements of his estimates in PGE Exhibit 2017.

Q. How does Mr. Gorman's recommended ROE of 9.7% compare to the authorized ROEs determined in past litigated decisions?

A. It is 20 basis points below the lowest ROE authorized in litigated cases for vertically-integrated electric utilities during the period 2005 to 2010 and 91 basis points below the average authorized ROE as reported by RRA. Thus—without any consideration of the way Mr. Gorman arrived at that recommendation—it also appears to be unfair for PGE.

A. Response to Mr. Gorman's DCF Analyses

Q. Do you have any comments about his constant growth DCF estimates?

A. Yes. The goal with this analysis as with other DCF analyses is to determine the best estimate of growth expected by investors. In forming his constant growth DCF estimate, Mr. Gorman relies on analysts' forecasts made by Zacks, SNL, and Reuters, but does not include forecasts reported by Yahoo! Finance or Value Line. Yahoo! Finance provides such estimates of growth for free on the internet and Value Line estimates are generally available to investors in public libraries. Thus, one should expect investors to be aware of Value Line and Yahoo! Finance growth rate estimates, while not necessarily being aware of SNL forecasts which generally require a subscription. At the time I prepared this testimony, the average[3] of growth forecasts reported by Yahoo! Finance was 6.1% and Value Line was 6.1%, both were higher than the 5.77% growth rate Mr. Gorman determined by relying on median and mean growth rates reported by the other financial institutions.

Q. Have you restated Mr. Gorman's constant growth analysis?

A. Yes. In making this restatement, I have added analysts' forecasts reported by Yahoo! Finance to those Mr. Gorman relied upon and recomputed his average of analysts' growth rates. These additional data increase his average growth rate from 5.77% to 5.90% and his cost of equity from 10.80% to 10.90% (see PGE Exhibit 2017).

Q. Mr. Gorman recommends the Commission give minimal, if any, weight to the constant growth DCF model. Do you agree?

A. No. Mr. Gorman makes this recommendation because he believes the growth rate used to determine the equity cost estimate is not sustainable and thus the equity cost estimate is too high. I do not agree for two primary reasons. First, neither Mr. Gorman nor I know what growth is expected by investors. If they expect growth of 5.9%, then they will price stocks—and thus reveal what they think is the required discount rate (the cost of equity) to hold such stocks—based on that growth rate.

Second, we don't know what model is used by investors. Given the constant growth DCF model is well-known and ubiquitous, information about the cost of equity revealed by that model should be considered. Value Line is currently forecasting GDP growth of 5.47%

[3] The averages for Value Line and Yahoo! Finance do not include a forecast for Allegheny Energy, as explained above.

and past GDP growth averaged 6.7%. A growth rate in the range of 5.47% to 6.7% may well be expected by investors, notwithstanding Mr. Gorman's personal view about the growth rate being "too big" to be sustained.

Q. Do you have any comments about his sustainable growth DCF model estimates of the cost of equity?

A. Yes. Mr. Gorman discusses this model at ICNU-CUB Exhibit 200, pages 31-32, and presents the results of his analysis at ICNU-CUB Exhibits 210 and 211. His analysis does not recognize that a negative value for "sv" growth is not sustainable in the long-term and results of his model are internally inconsistent with the underlying assumptions supporting it. Myron Gordon, often called the "Father of the DCF Model", explains that when the market to book ratio for a utility is less than 1.0 (and thus "v" is less than zero) and no new shares of stock are currently being issued, issuing stock "will make a bad situation worse". He states that when "v" is less than zero, the optimal course of action is not to issue stock.[4] Using Value Line forecasts for the next several years, Mr. Gorman estimates five of the stocks in his sample have negative values for "sv" growth. Such forecasts might be useful in the short-term, but are not "sustainable" in the long-term and investors would not expect a regulated utility to continue to issue shares below book value in the long-term.[5] As a result, Mr. Gorman and others looking at Value Line forecasts do not have data to compute estimates of "sv" growth which could be sustained in the long-term for those five utilities. By including them in his analysis, Mr. Gorman biases downward the average DCF estimate

[4] Myron Gordon, The Cost of Capital to a Public Utility, 1974, page 162. Gordon also explained that only positive values of sv growth should be considered in that a utility would not choose to issue shares of stock if sv growth were expected to be negative. Utilities have, however, issued shares of stock when market to book ratios were below 1 to maintain reasonable capital structures and obtain financing to provide the facilities needed to maintain high quality of service for their ratepayers.

[5] Or, in the case of Entergy Corporation, buy back shares indefinitely.

of the cost of equity from 10.25% to 9.92% and the median estimates of the cost of equity from 9.75% to 9.54% (see PGE Exhibit 2018).

The results of Mr. Gorman's model are also internally inconsistent. In formulating his growth rate estimate he relied on Value Line forecasts of "b" (the predicted retention ratio) and an average ROE forecast ("r") of 10.95%. Mr. Gorman's sustainable growth DCF model, however, returns an average ROE estimate of only 9.92%, 103 basis points lower than the 10.95% ROE he said was expected to be earned, and a median ROE estimate of 9.54%, 141 basis points lower than the 10.95% ROE expected to be earned. With regulated utilities, it is unreasonable to assume the 10.95% ROE will be consistently earned if regulators authorized only 9.54% or 9.92%. Consistency requires that the commissions authorize 10.95% if an ROE of 10.95% is to be sustained. At least in this instance, as Mr. Gorman applies this model, results of the sustainable growth model are internally inconsistent.

In restating this model, there is no simple "fix" or "update" and thus I assign a "no meaningful figure" to the update and restatement. If the model were to be considered, the minimum value that could be assigned is the 10.25% estimate that eliminates utilities for which there are short-term negative forecasts of "sv" growth; the 10.95% average ROE, which presumably would be sustainable if authorized, should be considered as well.

Q. Have you updated Mr. Gorman's multi-stage DCF model?

A. Yes. In making this restatement, the only change I have adopted is to assume investors would expect future GDP growth during Mr. Gorman's third (long-term) period to be an average of his Blue Chip forecast of 4.8% and the June 18, 2010, Value Line forecast GDP growth of 5.47%. This average is 5.13%. After making this change, the average internal rate of return increases from 10.02% to 10.31% (see PGE Exhibit 2017).

Q. Do you agree that 10.31% is a reasonable result for this model?

A. No. I disagree with the final result because it does not account for the time value of money—determined by Mr. Storm to be worth about 20 basis points—and the GDP growth in the final period of 5.13% is too low. I anticipate investors would look to the past as well as intermediate-term forecasts made by Blue Chip and Value Line and find a very long-term growth rate of 5.8% is expected. In such a case, the multi-period DCF model would produce results closer to the 11.0% value I estimate in PGE Exhibit 2006.

B. Response to Mr. Gorman's CAPM Analysis

Q. Do you have any responses to his CAPM estimates?

A. Yes. I believe the Commission was correct when it determined very limited weight should be given to CAPM estimates. Especially at this time when financial markets are so turbulent, it is difficult to determine the correct values to adopt for the zero-beta asset (or risk-free rate, RF) and the market risk premium (MRP), and which version of the CAPM is appropriate. Notwithstanding those concerns, I limit my response to Mr. Gorman's determination of the MRP expected by investors at this time.

Q. Do you agree that a 6.7% MRP should be considered?

A. Yes, I believe one of the MRP values which might be considered by investors is 6.7%. This is the long-horizon average MRP reported by Morningstar in the 2010 Ibbotson SBBI Valuation Yearbook and is well-known by investors. Given the turmoil and uncertainty in equity markets at this time, I believe this long-horizon average is the floor beneath any reasonable value investors expect for the MRP.

Q. What are some other values of the MRP which investors might consider?

A. Two come to mind. One is the implied MRP which can be computed from the first page of the June 18, 2010, Value Line Summary & Index. Based on the 2.1% dividend yield and

75% four-year appreciation potential for a large group of stocks, the expected ROE for stocks in general is 17.4%[6] and the implied expected market risk premium is 12.1%, given Mr. Gorman's forecast of the RF of 5.3%.[7] I do not rely on this MRP estimate to restate Mr. Gorman's CAPM cost of equity estimate, but note some investors might rely on it.

Q. What is the other MRP estimate that you mentioned?

A. The other is a market risk premium derived from forecasts Value Line has made for its Industrial Composite for many years in the past. The Industrial Composite consists of over 500 industrial, retail and transportation companies which are included in 72 of Value Line's 98 industry groups. Data for these companies are pooled as if they belong to one large conglomerate. Given the breadth of the industries included, I expect this Industrial Composite provides useful data to estimate DCF costs of equity for the market as a whole.

PGE Exhibit 2019 contains data for this Industrial Composite for the period 1985 to 2009. During the full period, the average MRP estimate was 6.6%, very close to the 6.7% long-horizon average MRP reported by Morningstar. An estimate of the expected MRP during the most recent 10-year period is 7.4%. I have used that value as a second estimate of the MRP expected by investors. With a 5.3% value for RF and a beta estimate of .71 relied upon by Mr. Gorman, this estimate of the MRP indicates a CAPM cost of equity of 10.55%.[8]

I give this 10.55% CAPM estimate and Mr. Gorman's 10.06% CAPM estimate equal weight to restate Mr. Gorman's CAPM estimate to be 10.3%.

Q. Should any weight be given to Mr. Gorman's MRP estimate of 5.2%?

[6] Where the appreciation potential is computed as (1.75)^(1/4) -1 = 15% and the market return is computed as 2.1% x 1.15 + 15% = 17.4%.
[7] Found as 17.4% - 5.3% = 12.1%.
[8] 5.3% + 0.71 x 7.4% = 10.55%

A. No. This estimate presumes prior increases of price-to-earnings ratios could not be sustained. With the current flight to quality and dramatic drop and partial recovery of the stock market, I do not believe such a method is appropriate at this time.

C. Response to Mr. Gorman's Adjustment for PGE's PCAM

Q. Mr. Gorman suggests that an adjustment to PGE's authorized ROE should be made in order to "reflect the risk reduction created by the PCAM mechanism." Do you agree?

A. No. Mr. Gorman offers no comparison of PGE's currently approved or proposed PCAM with the mechanisms in place for other firms in the sample he used to determine ROE estimates. In my direct testimony in PGE Exhibit 1200, I did discuss how PGE's PCAM compares with those of other firms. The results of my review indicated that the, "risk reducing benefits of a typical PCAM are already in the cost of equity estimates for the benchmark sample in PGE Exhibit 1201" (PGE Exhibit 1200, page 16). The PCAM currently approved for PGE, however, does not offset as much uncertainty as the "typical" mechanism in place for firms included in my review. In my direct testimony, I went on to state that the modifications to the current PCAM proposed by PGE will, "make risks of recovery of power costs more in line with the risks of the peer group" (PGE Exhibit 1200, page 16). Thus, a downward adjustment to PGE's authorized ROE in consideration of the modifications proposed to the PCAM is not warranted. The proposal merely makes PGE more comparable with the sample.

D. Response to Mr. Gorman's Critiques of PGE's ROE Analyses

Q. Please turn to your responses to his comments about your equity cost estimates. Do you have a response to Mr. Gorman's comments about your constant growth DCF model?

A. No. I included the Yahoo! Finance growth rates in the average of growth rates he used to revise my analysis and found it had virtually no impact on his restatement of my analysis. In both cases, if the time value of money is not recognized, the indicated cost of equity is 10.9%. Had the time value of money been recognized, the average equity cost estimate would have exceeded 11.0% (see PGE Exhibit 2020).

Q. Do you have a response to his restatement of your application of the FERC DCF model?

A. Yes. Mr. Gorman arbitrarily eliminated several high growth forecasts from the analysis. I explained in PGE Exhibit 1200, pages 24-25, that the range of equity costs produced with this method is large because the equity costs were not based on consensus estimates of growth, but the mid-point of the range of equity costs produced with the high and low growth rates provides reasonable equity cost estimates. If equity cost estimates made with the high growth rates are arbitrarily eliminated from the analysis, the mid-point is arbitrarily biased downward. This method requires those equity cost estimates to be included in the analysis and not arbitrarily eliminated.

Q. Have you restated his revision of your FERC-model DCF analysis?

A. Yes, I have. Once the equity costs based on the high growth rates are included, the indicated mid-point cost of equity estimate is 10.7%. If the time value of money had been recognized in this analysis, the restated cost of equity would be higher.

Q. Mr. Gorman finds that his restatement of your multi-period DCF analysis produces an equity cost of only 9.6%. Has he made an error in that restatement?

A. Yes. Mr. Gorman made a serious error in the spreadsheet used to determine his restatement of my multi-period DCF analysis. The error is that he appears to have inadvertently included the growth rate used to grow cash flows in the first period as the first positive cash flow in his internal rate of return (IRR) calculation. In the case of Ameren, for example, his spreadsheet assumed the first cash flow was $0.03 (the 3% growth rate) instead of the first period dividend of $1.60. He made the same mistake for each of the 31 utilities. This error had the effect of reducing the average IRR from 10.1% to 9.6%, a drop of 50 basis points (see PGE Exhibit 2020).

Q. After fixing this error, do you agree with his restatement of your multi-stage DCF analysis?

A. No. I explained in my direct testimony why I believe investors would consider 5.8% a reasonable estimate of long-term GDP growth. Mr. Gorman has relied upon an estimate of only 4.8% to restate my analysis. That is an estimate provided by Blue Chip. To be conservative in my response to his restatement, I have used another intermediate-term forecast of GDP growth, the forecast made by Value Line at June 18, 2010, as the estimate of long-horizon GDP growth expected by investors. Based on that GDP forecast of 5.47%, the indicated average cost of equity is 10.5% (see PGE Exhibit 2020). Had I restated this analysis to include recognition of the time value of money and my long-term GDP forecast of 5.8%, the average equity cost would have been close to the updated estimate I present in PGE Exhibit 2006 of 11.0%.

Q. Do you have a response to Mr. Gorman's contention that it is inappropriate to adjust dividends for the time value of money?

A. Yes. At ICNU-CUB Exhibit 200, pages 54-55, he contends that such an adjustment allows shareholders to earn the dividend reinvestment return twice: once through a higher authorized ROE and then again by allowing investors to reinvest those dividends. He never addresses the reason such an adjustment must be made; the present value of a dividend paid at year-end is less than the present value of one-fourth of that dividend being paid quarterly.

Thus, investors prefer to get dividends sooner rather than later and bid up the price they are willing to pay for stocks that pay quarterly dividends rather than annual dividends. Unless the time-value of money is recognized when computing the DCF model, it will be inconsistent with knowledge that investors bid up those stock prices to reflect benefits of receiving dividends quarterly.

Q. Do his examples at ICNU-CUB Exhibit 200, pages 56-57, justify rejection of your adjustment for the time value of money?

A. No. The examples fail to address the fact that stock prices—which are incorporated in DCF estimates—already reflect the fact that investors prefer quarterly dividends to annual dividends. His reference to PGE bonds (at ICNU-CUB Exhibit 200, page 56) does not address the issue. The OPUC determines how such costs will be recovered.

His example at ICNU-CUB Exhibit 200, page 57, related to PGE stock does not address the issue either. In this example, he fails to address the reason the investor paid $100 for PGE stock. He suggests an investor paying $100 for stock is indifferent between receiving $1.50 in quarterly dividend payments and receiving one $6.00 payment at the end of the year. In effect, he ignores the fact that the $100 being paid is a higher price than would be paid if the investors got only one $6.00 payment per year. Unless the time value of money is taken into account, the equity cost estimate revealed by the DCF model will understate the cost of equity reflected by the investor paying $100 for the stock in anticipation of quarterly dividend payments.

V. Conclusion

Q. Please summarize your comments regarding Mr. Storm's testimony in Staff Exhibit 900.

A. Mr. Storm presents just a single method to estimate PGE's RROE. Further, he ignores analyst EPS growth estimates and historical GDP growth. Mr. Storm misquotes Dr. Roger Morin repeatedly. These quotes actually contradict, rather than support Mr. Storm when they are read in their entirety. His recommended ROE is clearly unreasonable as it is 70 basis points below the lowest ROE authorized in the country since 2005.

Q. Please summarize your comments regarding Mr. Gorman's testimony in ICNU-CUB Exhibit 200.

A. Mr. Gorman's analyses are flawed with inconsistencies and errors. His analyses lead to a recommended ROE that is 20 basis point below the lowest ROE authorized in the country since 2005. He proposes this low ROE recommendation be further reduced by 25 basis points if PGE's proposed PCAM modifications are adopted. Mr. Gorman, however, fails to recognize PCAMs of utilities used to determine benchmark ROE estimates are in line with PGE's proposal and thus no ROE adjustment is warranted if PGE's PCAM is modified as proposed. A restatement of his analyses, to the extent possible, results in an average ROE of 10.51%, with no reduction for the proposed PCAM modifications.

Q. What is your ROE recommendation for PGE based on the updates provided in this testimony?

A. My ROE recommendation for PGE is 11.27%, above PGE's requested ROE of 10.50%. The summary results of my updated ROE analyses are provided in PGE Exhibit 2011.

Q. Does this conclude your rebuttal testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
2001	Current Annualized Average Dividend Yields for Electric Utilities Sample
2002	Estimates of Growth Based on Analysts' Forecasts Reported by Value Line, Reuters, Yahoo! Finance and Zacks
2003	Application of the Constant Growth DCF Model
2004	Range of Growth Rates Reported by Four Investor Services
2005	Application of the FERC Multi-period DCF Method
2006	Alternative Multi-Stage DCF Growth Analysis
2007	Forecasts of Treasury and Baa Corporate Bond Rates
2008	Risk Premium Analysis: Method Used by Department of Ratepayer Advocates of the California PUC with Data for Prior Oregon PUC Sample 2000 to 2009
2009	Risk Premium Analysis Based on Moody's Index and Updates
2010	Risk Premiums Determined by Relationship Between Authorized ROEs and Baa Corporate Bond Rates During the Period 1985-2008
2011	Summary Table: Updated Estimated Costs of Equity for Benchmark Samples and PGE
2012	Perspective for ROEs and Estimated Equity Costs Proposed by Staff, ICNU-CUB, and PGE
2013	Restatement of Mr. Storm's Analysis: Revise growth rates in 2012 to 2015; leave others the same
2014	Comparison of Current Average of Analysts' Forecast to Data Provided in UE 197/PGE Exhibit 1003
2015	Revise Growth in 2012-2015 and adopt Mr. Storm's GDP Forecasts of 4.75% and 5.86%
2016	Examination of Bias in Real and Nominal Value Line ROE Forecasts for 8 Natural Gas Utilities 1977 to 1998

2017	Rebuttal of Mr. Gorman's Equity Cost Estimates
2018	Restatement of Mr. Gorman's Sustainable Constant Growth DCF Model
2019	Market Risk Premium Implied by Analysis of Value Line's Industrial Composite
2020	Rebuttal of Mr. Gorman's Restatements of Dr. Zepp's Equity Cost Estimates
2021	Appendix 4-A, New Regulatory Finance

Portland General Electric

PGE Exhibit 2001 (page 1)
Update of PGE Exhibit 1205

Current Annualized Average Dividend Yields for Electric Utilities Sample

		Yield[a/] Based on 3-month Range of Prices	Dividend Forecast[a/] Adjusted for Time Value of Money	3-month[b/] High Stock Price	3-month[b/] Low Stock Price
na	Allegheny Energy, Inc.[c/]	[c/]	[c/]	[c/]	[c/]
1	ALLETE, Inc.	5.20%	$1.83	$37.87	$32.90
2	Alliant Energy Corporation	5.11%	$1.64	$35.77	$29.20
3	Ameren Corporation	6.48%	$1.61	$26.92	$23.09
4	American Electric Power Co.	5.59%	$1.75	$35.00	$28.26
5	Avista Corporation	5.26%	$1.06	$22.25	$18.46
6	Cleco Corporation	3.92%	$1.04	$28.28	$24.91
7	CMS Energy Corporation	4.22%	$0.64	$16.67	$14.09
8	DPL Inc.	4.85%	$1.26	$28.44	$23.83
9	DTE Energy Company	4.81%	$2.20	$49.05	$43.00
10	Duke Energy Corporation	6.27%	$1.02	$17.14	$15.47
11	Edison International	4.14%	$1.34	$34.74	$30.37
12	Empire District Electric Co.	7.11%	$1.33	$20.00	$17.57
13	Entergy Corporation	4.47%	$3.45	$84.33	$71.28
14	FPL Group (now NextEra Energy)	4.21%	$2.13	$53.50	$48.14
15	Great Plains Energy Incorporated	4.80%	$0.86	$19.50	$16.67
16	Hawaiian Electric Industries, Inc.	5.74%	$1.29	$24.04	$21.07
17	IDACORP, Inc.	3.69%	$1.25	$36.93	$31.22
18	MGE Energy, Inc.	4.23%	$1.53	$38.40	$34.15
19	Northwestern Corporation	5.27%	$1.46	$30.60	$25.15
20	OGE Energy Corp.	4.06%	$1.53	$42.25	$33.87
21	PG&E Corporation	4.91%	$1.93	$45.00	$34.95
22	Pinnacle West Capital Corp.	6.17%	$2.18	$39.10	$32.31
23	Portland General Electric	5.58%	$1.08	$20.60	$18.26
24	Progress Energy Inc.	6.64%	$2.58	$40.69	$37.13
25	Southern Company	5.68%	$1.91	$35.45	$32.04
26	TECO Energy, Inc.	5.47%	$0.86	$17.35	$14.46
27	UIL Holdings	6.75%	$1.80	$30.33	$23.79
28	UniSource Energy Corporation	5.13%	$1.62	$34.43	$29.20
29	Westar Energy, Inc.	5.75%	$1.29	$23.93	$21.10
30	Wisconsin Energy Corporation	3.43%	$1.72	$53.80	$46.84
31	Xcel Energy Inc.	5.02%	$1.05	$22.14	$19.81
	Average	5.16%			

Notes and Sources:

a/ Dividend yields (D_1/P_0) are based on Value Line's May 28, 2010 forecasts of dividends (D_1) for the next year corrected for the time value of money.

b/ Prices (P_0) are the highest and lowest prices during the period April 2010 to June 2010.

c/ Not included due to pending merger with FirstEnergy.

Portland General Electric

PGE Exhibit 2001 (page 2)
Update of PGE Exhibit 1205 using Mr. Storm's Sample

Current Annualized Average Dividend Yields
for Mr. Storm's Electric Utilities Sample

		Yield[a/] Based on 3-month Range of Prices	Dividend Forecast[a/] Adjusted for Time Value of Money	3-month[b/] High Stock Price	3-month[b/] Low Stock Price
1	ALLETE, Inc.	5.20%	$1.83	$37.87	$32.90
2	American Electric Power Co.	5.59%	$1.75	$35.00	$28.26
3	Cleco Corporation	3.92%	$1.04	$28.28	$24.91
4	Empire District Electric Co.	7.11%	$1.33	$20.00	$17.57
5	IDACORP, Inc.	3.69%	$1.25	$36.93	$31.22
6	PG&E Corporation	4.91%	$1.93	$45.00	$34.95
7	Pinnacle West Capital Corp.	6.17%	$2.18	$39.10	$32.31
8	Progress Energy Inc.	6.64%	$2.58	$40.69	$37.13
9	TECO Energy, Inc.	5.47%	$0.86	$17.35	$14.46
10	UIL Holdings	6.75%	$1.80	$30.33	$23.79
11	Westar Energy, Inc.	5.75%	$1.29	$23.93	$21.10
12	Wisconsin Energy Corporation	3.43%	$1.72	$53.80	$46.84
13	Xcel Energy Inc.	5.02%	$1.05	$22.14	$19.81
	Average	5.36%			

Notes and Sources:

a/ Dividend yields (D_1/P_0) are based on Value Line's May 28, 2010 forecasts of dividends (D_1) for the next year corrected for the time value of money.

b/ Prices (P_0) are the highest and lowest prices during the period April 1, 2010 to June 7, 2010.

Portland General Electric

PGE Exhibit 2002 (page 1)
Update of PGE Exhibit 1206

Estimates of Growth Based on Analysts' Forecasts Reported by Value Line, Reuters, Yahoo! Finance and Zacks[a]

		Value Line[a]	Zacks[b]	Yahoo![b]	Reuters[b]	Average[c]
		(a)	(b)	(c)	(d)	(e)
na	Allegheny Energy, Inc.[d]					
1	ALLETE, Inc.	3.2	3.7	6.5	8.0	5.4
2	Alliant Energy Corporation	7.0	4.0	8.5	8.5	7.0
3	Ameren Corporation	1.0	nmf	nmf	4.0	2.5
4	American Electric Power Co.	3.0	4.0	4.0	4.7	3.9
5	Avista Corporation	8.5	4.5	4.3	4.0	5.3
6	Cleco Corporation	8.0	9.0	7.0	7.0	7.8
7	CMS Energy Corporation	9.5	5.8	6.0	6.3	6.9
8	DPL Inc.	6.5	5.0	5.9	11.7	7.3
9	DTE Energy Company	7.0	5.0	4.9	4.5	5.4
10	Duke Energy Corporation	5.0	1.0	4.4	2.0	3.1
11	Edison International	0.5	5.0	2.0	3.0	2.6
12	Empire District Electric Co.	7.0	na	6.0	na	6.5
13	Entergy Corporation	5.0	5.0	6.7	10.0	6.7
14	FPL Group (now NextEra Energy)	5.0	6.6	6.7	6.8	6.3
15	Great Plains Energy Inc.	4.5	9.5	13.0	9.7	9.2
16	Hawaiian Electric Industries, Inc.	11.5	9.5	7.6	7.6	9.1
17	IDACORP, Inc.	5.5	5.0	4.7	4.7	5.0
18	MGE Energy, Inc.	6.0	5.0	5.0	na	5.3
19	Northwestern Corporation	na	7.0	7.0	7.0	7.0
20	OGE Energy Corp.	5.0	5.5	4.0	4.5	4.8
21	PG&E Corporation	7.0	7.3	6.9	6.8	7.0
22	Pinnacle West Capital Corp.	6.0	7.0	6.6	6.3	6.5
23	Portland General Electric	3.0	5.2	5.0	4.8	4.5
24	Progress Energy Inc.	3.5	4.0	3.9	4.1	3.9
25	Southern Company	4.5	4.9	5.1	5.0	4.9
26	TECO Energy, Inc.	8.0	6.4	6.3	8.1	7.2
27	UIL Holdings	3.0	4.0	4.1	4.1	3.8
28	UniSource Energy Corporation	14.0	5.0	5.0	na	8.0
29	Westar Energy, Inc.	7.5	8.0	9.3	7.0	7.9
30	Wisconsin Energy Corporation	8.0	9.5	9.5	8.8	9.0
31	Xcel Energy Inc.	5.5	5.7	6.4	6.0	5.9
	Average	6.0	5.8	6.1	6.3	6.0

Notes and Sources:

a/ Value Line Investment Survey Issue 1 (dated May 28, 2010), Issue 5 (dated March 26, 2010) Issue 11 (dated May 7, 2010) and Small and Mid-cap Issue 5 (dated March 26, 2010).
b/ Sources are analysts' forecasts reported on the Internet on June 8 and 9, 2010.
c/ Average of analysts' forecasts including Value Line.
d/ Not included due to pending merger with FirstEnergy.

Portland General Electric

PGE Exhibit 2002 (page 2)
Update of PGE Exhibit 1206 using Mr. Storm's Sample

Estimates of Growth Based on Analysts' Forecasts Reported by Value Line, Reuters, Yahoo! Finance and Zacks[a]

		Value Line[a]	Zacks[b]	Yahoo![b]	Reuters[b]	Average[c]
		(a)	(b)	(c)	(d)	(e)
1	ALLETE, Inc.[d]	3.2	3.7	6.5	8.0	5.4
2	American Electric Power Co.	3.0	4.0	4.0	4.7	3.9
3	Cleco Corporation	8.0	9.0	7.0	7.0	7.8
4	Empire District Electric Co.	7.0	na	6.0	na	6.5
5	IDACORP, Inc.	5.5	5.0	4.7	4.7	5.0
6	PG&E Corporation	7.0	7.3	6.9	6.8	7.0
7	Pinnacle West Capital Corp.	6.0	7.0	6.6	6.3	6.5
8	Progress Energy Inc.	3.5	4.0	3.9	4.1	3.9
9	TECO Energy, Inc.	8.0	6.4	6.3	8.1	7.2
10	UIL Holdings	3.0	4.0	4.1	4.1	3.8
11	Westar Energy, Inc.	7.5	8.0	9.3	7.0	7.9
12	Wisconsin Energy Corporation	8.0	9.5	9.5	8.8	9.0
13	Xcel Energy Inc.	5.5	5.7	6.4	6.0	5.9
	Average	5.8	6.1	6.2	6.3	6.1

Notes and Sources:

a/ Value Line Investment Survey Issue 1 (dated May 28, 2010), Issue 5 (dated March 26, 2010) and Issue 11 (dated May 7, 2010).
b/ Sources are analysts' forecasts reported on the Internet on June 8 and 9, 2010.
c/ Average of analysts' forecasts including Value Line.
d/ Forecast from 2010 to 2014.

Portland General Electric

PGE Exhibit 2003 (page 1)
Update of PGE Exhibit 1207

Application of the Constant Growth DCF Model

		D_1/P_0 [a]	G [b]	Equity Cost Estimates
na	Allegheny Energy, Inc. [c]			[c]
1	ALLETE, Inc.	5.20%	5.36%	10.56%
2	Alliant Energy Corporation	5.11%	6.98%	12.08%
3	Ameren Corporation	6.48%	2.50%	8.98%
4	American Electric Power Co.	5.59%	3.92%	9.50%
5	Avista Corporation	5.26%	5.33%	10.59%
6	Cleco Corporation	3.92%	7.75%	11.67%
7	CMS Energy Corporation	4.22%	6.90%	11.12%
8	DPL Inc.	4.85%	7.26%	12.11%
9	DTE Energy Company	4.81%	5.35%	10.16%
10	Duke Energy Corporation	6.27%	3.11%	9.37%
11	Edison International	4.14%	2.63%	6.77%
12	Empire District Electric Co.	7.11%	6.50%	13.61%
13	Entergy Corporation	4.47%	6.68%	11.15%
14	FPL Group (now NextEra Energy)	4.21%	6.27%	10.48%
15	Great Plains Energy Inc.	4.80%	9.17%	13.97%
16	Hawaiian Electric Industries, Inc.	5.74%	9.05%	14.79%
17	IDACORP, Inc.	3.69%	4.96%	8.65%
18	MGE Energy, Inc.	4.23%	5.33%	9.56%
19	Northwestern Corporation	5.27%	7.00%	12.27%
20	OGE Energy Corp.	4.06%	4.75%	8.81%
21	PG&E Corporation	4.91%	7.01%	11.92%
22	Pinnacle West Capital Corp.	6.17%	6.48%	12.65%
23	Portland General Electric	5.58%	4.50%	10.08%
24	Progress Energy Inc.	6.64%	3.87%	10.51%
25	Southern Company	5.68%	4.87%	10.55%
26	TECO Energy, Inc.	5.47%	7.19%	12.66%
27	UIL Holdings	6.75%	3.82%	10.56%
28	UniSource Energy Corporation	5.13%	8.00%	13.13%
29	Westar Energy, Inc.	5.75%	7.95%	13.69%
30	Wisconsin Energy Corporation	3.43%	8.96%	12.39%
31	Xcel Energy Inc.	5.02%	5.89%	10.91%
	Column Average	5.2%	6.0%	11.1%

Notes and Sources:
a/ Dividend yields (D_1/P_0) developed in PGE Exhibit 2001/1
b/ Growth rates are the average growth rates reported in PGE Exhibit 2002/1
c/ Not included due to pending merger with FirstEnergy.

Portland General Electric

PGE Exhibit 2003 (page 2)
Update of PGE Exhibit 1207 using Mr. Storm's Sample

Application of the Constant Growth DCF Model

		D_1/P_0 [a/]	G [b/]	Equity Cost Estimates
1	ALLETE, Inc.	5.20%	5.35%	10.55%
2	American Electric Power Co.	5.59%	3.92%	9.50%
3	Cleco Corporation	3.92%	7.75%	11.67%
4	Empire District Electric Co.	7.11%	6.50%	13.61%
5	IDACORP, Inc.	3.69%	4.96%	8.65%
6	PG&E Corporation	4.91%	7.01%	11.92%
7	Pinnacle West Capital Corp.	6.17%	6.48%	12.65%
8	Progress Energy Inc.	6.64%	3.87%	10.51%
9	TECO Energy, Inc.	5.47%	7.19%	12.66%
10	UIL Holdings	6.75%	3.82%	10.56%
11	Westar Energy, Inc.	5.75%	7.95%	13.69%
12	Wisconsin Energy Corporation	3.43%	8.96%	12.39%
13	Xcel Energy Inc.	5.02%	5.89%	10.91%
	Column Average	5.4%	6.1%	11.5%

Notes and Sources:

a/ Dividend yields (D_1/P_0) developed in PGE Exhibit 2001/2

b/ Growth rates are the average growth rates reported in PGE Exhibit 2002/2

Portland General Electric

PGE Exhibit 2004 (page 1)
Update of PGE Exhibit 1208

Range of Growth Rates Reported by Four Investor Services[a]

		Range of Analysts' Forecasts		
		Maximum	Minimum	Mid-point
na	Allegheny Energy, Inc.[b]			
1	ALLETE, Inc.	8.0%	3.2%	5.6%
2	Alliant Energy Corporation	8.5%	4.0%	6.2%
3	Ameren Corporation	4.0%	1.0%	2.5%
4	American Electric Power Co.	4.7%	3.0%	3.8%
5	Avista Corporation	8.5%	4.0%	6.3%
6	Cleco Corporation	9.0%	7.0%	8.0%
7	CMS Energy Corporation	9.5%	5.8%	7.7%
8	DPL Inc.	11.7%	5.0%	8.4%
9	DTE Energy Company	7.0%	4.5%	5.8%
10	Duke Energy Corporation	5.0%	1.0%	3.0%
11	Edison International	5.0%	0.5%	2.8%
12	Empire District Electric Co.	7.0%	6.0%	6.5%
13	Entergy Corporation	10.0%	5.0%	7.5%
14	FPL Group (now NextEra Energy)	6.8%	5.0%	5.9%
15	Great Plains Energy Inc.	13.0%	4.5%	8.8%
16	Hawaiian Electric Industries, Inc.	11.5%	7.6%	9.6%
17	IDACORP, Inc.	5.5%	4.7%	5.1%
18	MGE Energy, Inc.	6.0%	5.0%	5.5%
19	Northwestern Corporation	7.0%	7.0%	7.0%
20	OGE Energy Corp.	5.5%	4.0%	4.8%
21	PG&E Corporation	7.3%	6.8%	7.1%
22	Pinnacle West Capital Corp.	7.0%	6.0%	6.5%
23	Portland General Electric	5.2%	3.0%	4.1%
24	Progress Energy Inc.	4.1%	3.5%	3.8%
25	Southern Company	5.1%	4.5%	4.8%
26	TECO Energy, Inc.	8.1%	6.3%	7.2%
27	UIL Holdings	4.1%	3.0%	3.6%
28	UniSource Energy Corporation	14.0%	5.0%	9.5%
29	Westar Energy, Inc.	9.3%	7.0%	8.1%
30	Wisconsin Energy Corporation	9.5%	8.0%	8.8%
31	Xcel Energy Inc.	6.4%	5.5%	5.9%
	Column average	7.5%	4.7%	6.1%

Notes and Sources:

a/ Sources are Value Line, Reuters' consensus estimates, Zacks and Yahoo! Finance. See PGE Exhibit 2002/1.

b/ Not included due to pending merger with FirstEnergy.

Portland General Electric

PGE Exhibit 2004 (page 2)

Update of PGE Exhibit 1208 using Mr. Storm's Sample

Range of Growth Rates Reported by Four Investor Services[a/]

		Range of Analysts' Forecasts		
		Maximum	Minimum	Mid-point
1	ALLETE, Inc.	8.0%	3.2%	5.6%
2	American Electric Power Co.	4.7%	3.0%	3.8%
3	Cleco Corporation	9.0%	7.0%	8.0%
4	Empire District Electric Co.	7.0%	6.0%	6.5%
5	IDACORP, Inc.	5.5%	4.7%	5.1%
6	PG&E Corporation	7.3%	6.8%	7.1%
7	Pinnacle West Capital Corp.	7.0%	6.0%	6.5%
8	Progress Energy Inc.	4.1%	3.5%	3.8%
9	TECO Energy, Inc.	8.1%	6.3%	7.2%
10	UIL Holdings	4.1%	3.0%	3.6%
11	Westar Energy, Inc.	9.3%	7.0%	8.1%
12	Wisconsin Energy Corporation	9.5%	8.0%	8.8%
13	Xcel Energy Inc.	6.4%	5.5%	5.9%
	Column average	6.9%	5.4%	6.1%

Notes and Sources:

a/ Sources are Value Line, Reuters' consensus estimates, Zacks and Yahoo! Finance. See PGE Exhibit 2002/2.

Portland General Electric

PGE Exhibit 2005 (page 1)
Update of PGE Exhibit 1209

Application of the FERC Multi-period DCF Method

			Low Estimate			High Estimate	
		D_1/P_0	Low Growth	Low Equity Cost Estimate		High Growth	High Equity Cost Estimate
na	Allegheny Energy, Inc. [c/]						
1	ALLETE, Inc.	5.20%	4.10%	9.29%		7.28%	12.48%
2	Alliant Energy Corporation	5.11%	4.60%	9.71%		7.58%	12.69%
3	Ameren Corporation	6.48%	2.59%	9.07%		4.60%	11.08%
4	American Electric Power Co.	5.59%	3.93%	9.52%		5.05%	10.63%
5	Avista Corporation	5.26%	4.60%	9.86%		7.61%	12.87%
6	Cleco Corporation	3.92%	6.61%	10.53%		7.95%	11.87%
7	CMS Energy Corporation	4.22%	5.81%	10.03%		8.28%	12.51%
8	DPL Inc.	4.85%	5.27%	10.12%		9.76%	14.61%
9	DTE Energy Company	4.81%	4.93%	9.74%		6.61%	11.42%
10	Duke Energy Corporation	6.27%	2.59%	8.86%		5.27%	11.54%
11	Edison International	4.14%	2.25%	6.39%	[b/]	5.27%	9.41%
12	Empire District Electric Co.	7.11%	5.94%	13.05%		6.61%	13.72%
13	Entergy Corporation	4.47%	5.27%	9.74%		8.64%	13.11%
14	FPL Group (now NextEra Energy)	4.21%	5.27%	9.48%		6.50%	10.70%
15	Great Plains Energy Inc.	4.80%	4.93%	9.74%		10.63%	15.43%
16	Hawaiian Electric Industries, Inc.	5.74%	7.01%	12.75%		9.62%	15.37%
17	IDACORP, Inc.	3.69%	5.05%	8.74%		5.60%	9.29%
18	MGE Energy, Inc.	4.23%	5.27%	9.50%		5.94%	10.17%
19	Northwestern Corporation	5.27%	6.61%	11.88%		6.61%	11.88%
20	OGE Energy Corp.	4.06%	4.60%	8.66%		5.60%	9.67%
21	PG&E Corporation	4.91%	6.49%	11.40%		6.81%	11.73%
22	Pinnacle West Capital Corp.	6.17%	5.94%	12.11%		6.61%	12.78%
23	Portland General Electric	5.58%	3.93%	9.51%		5.40%	10.99%
24	Progress Energy Inc.	6.64%	4.26%	10.91%		4.64%	11.28%
25	Southern Company	5.68%	4.93%	10.62%		5.31%	10.99%
26	TECO Energy, Inc.	5.47%	6.11%	11.58%		7.34%	12.81%
27	UIL Holdings	6.75%	3.93%	10.68%		4.69%	11.43%
28	UniSource Energy Corporation	5.13%	5.27%	10.40%		11.30%	16.43%
29	Westar Energy, Inc.	5.75%	6.61%	12.36%		8.14%	13.89%
30	Wisconsin Energy Corporation	3.43%	7.28%	10.71%		8.31%	11.73%
31	Xcel Energy Inc.	5.02%	5.60%	10.63%		6.17%	11.20%
	Average			10.2%			12.1%
	Mid-point					11.2%	

Notes and Sources:

a/ Use FERC method of assigning a weight of two-thirds to average EPS growth rates reported in PGE Exhibit 2004/1 and one-third to a forecast of future GPD growth of 5.8%.

b/ Low equity cost estimate equal to or below the expected cost of investment grade debt of 7.07%. See PGE Exhibit 2007. To be conservative, estimates are included in average.

c/ Not included due to pending merger with FirstEnergy.

Portland General Electric

PGE Exhibit 2005 (page 2)
Update of PGE Exhibit 1209 using Mr. Storm's Sample

Application of the FERC Multi-period DCF Method

			Low Estimate		High Estimate	
		D_1/P_0	Low Growth	Low Equity Cost Estimate	High Growth	High Equity Cost Estimate
1	ALLETE, Inc.	5.20%	4.10%	9.29%	7.28%	12.48%
2	American Electric Power Co.	5.59%	3.93%	9.52%	5.05%	10.63%
3	Cleco Corporation	3.92%	6.61%	10.53%	7.95%	11.87%
4	Empire District Electric Co.	7.11%	5.94%	13.05%	6.61%	13.72%
5	IDACORP, Inc.	3.69%	5.05%	8.74%	5.60%	9.29%
6	PG&E Corporation	4.91%	6.49%	11.40%	6.81%	11.73%
7	Pinnacle West Capital Corp.	6.17%	5.94%	12.11%	6.61%	12.78%
8	Progress Energy Inc.	6.64%	4.26%	10.91%	4.64%	11.28%
9	TECO Energy, Inc.	5.47%	6.11%	11.58%	7.34%	12.81%
10	UIL Holdings	6.75%	3.93%	10.68%	4.69%	11.43%
11	Westar Energy, Inc.	5.75%	6.61%	12.36%	8.14%	13.89%
12	Wisconsin Energy Corporation	3.43%	7.28%	10.71%	8.31%	11.73%
13	Xcel Energy Inc.	5.02%	5.60%	10.63%	6.17%	11.20%
	Average			10.9%		11.9%
	Mid-point				11.4%	

Notes and Sources:

a/ Use FERC method of assigning a weight of two-thirds to average EPS growth rates reported in PGE Exhibit 2004/2 and one-third to a forecast of future GPD growth of 5.8%.

Portland General Electric

PGE Exhibit 2006 (page 1)
Update of PGE Exhibit 1210

Alternative Multi-Stage DCF Growth Analysis

		Internal Rate of Return	P_0	First Year Dividend D_1[a/] D_{2010}	Stage 1[b/] D_{2011}	D_{2015}	Stage 2 and 3[c,d/] D_{2016}	$(P+D)_{2025}$	P_{2025}[d/]
na	Allegheny Energy, Inc.[e/]	nmf							
1	ALLETE, Inc.	10.61%	-$35.39	$1.83	$1.93	$2.38	$2.50	$86.61	$82.51
2	Alliant Energy Corporation	11.29%	-$32.49	$1.64	$1.76	$2.30	$2.46	$86.50	$82.24
3	Ameren Corporation	10.95%	-$25.01	$1.61	$1.65	$1.82	$1.87	$60.22	$57.44
4	American Electric Power Co.	10.65%	-$31.63	$1.75	$1.82	$2.12	$2.20	$78.65	$75.21
5	Avista Corporation	10.85%	-$20.36	$1.06	$1.12	$1.37	$1.45	$52.19	$49.81
6	Cleco Corporation	10.31%	-$26.60	$1.04	$1.12	$1.51	$1.62	$70.85	$67.97
7	CMS Energy Corporation	10.35%	-$15.38	$0.64	$0.69	$0.90	$0.96	$40.41	$38.75
8	DPL Inc.	11.14%	-$26.14	$1.26	$1.35	$1.79	$1.91	$69.85	$66.51
9	DTE Energy Company	10.45%	-$46.03	$2.20	$2.32	$2.86	$3.01	$117.68	$112.75
10	Duke Energy Corporation	11.00%	-$16.31	$1.02	$1.05	$1.19	$1.23	$39.83	$37.97
11	Edison International	9.05%	-$32.56	$1.34	$1.38	$1.53	$1.57	$79.05	$76.70
12	Empire District Electric Co.	13.21%	-$18.79	$1.33	$1.42	$1.82	$1.94	$50.58	$47.28
13	Entergy Corporation	10.53%	-$77.81	$3.45	$3.68	$4.77	$5.08	$204.09	$195.38
14	FPL Group (now NextEra Energy)	10.15%	-$50.82	$2.13	$2.26	$2.89	$3.07	$131.78	$126.60
15	Great Plains Energy Inc.	11.80%	-$18.09	$0.86	$0.94	$1.34	$1.46	$50.71	$48.00
16	Hawaiian Electric	12.86%	-$22.56	$1.29	$1.41	$1.99	$2.16	$64.31	$60.30
17	IDACORP, Inc.	9.25%	-$34.08	$1.25	$1.31	$1.59	$1.67	$85.85	$83.15
18	MGE Energy, Inc.	9.88%	-$36.28	$1.53	$1.61	$1.98	$2.09	$92.34	$88.92
19	Northwestern Corporation	11.48%	-$27.88	$1.46	$1.56	$2.04	$2.18	$74.44	$70.66
20	OGE Energy Corp.	9.53%	-$38.06	$1.53	$1.60	$1.93	$2.02	$95.72	$92.48
21	PG&E Corporation	11.07%	-$39.98	$1.93	$2.07	$2.71	$2.90	$106.21	$101.19
22	Pinnacle West Capital Corp.	12.21%	-$35.71	$2.18	$2.32	$2.99	$3.18	$95.06	$89.65
23	Portland General Electric	10.90%	-$19.43	$1.08	$1.13	$1.35	$1.41	$48.96	$46.72
24	Progress Energy Inc.	11.63%	-$38.91	$2.58	$2.68	$3.12	$3.24	$96.89	$91.84
25	Southern Company	11.13%	-$33.75	$1.91	$2.01	$2.43	$2.55	$85.82	$81.72
26	TECO Energy, Inc.	11.76%	-$15.91	$0.86	$0.92	$1.22	$1.31	$42.80	$40.52
27	UIL Holdings	11.63%	-$27.06	$1.80	$1.87	$2.17	$2.26	$67.30	$63.79
28	UniSource Energy Corporation	11.72%	-$31.82	$1.62	$1.75	$2.38	$2.57	$87.03	$82.43
29	Westar Energy, Inc.	12.40%	-$22.52	$1.29	$1.39	$1.89	$2.04	$62.15	$58.51
30	Wisconsin Energy Corp	10.10%	-$50.32	$1.72	$1.87	$2.63	$2.86	$136.14	$130.85
31	Xcel Energy Inc.	10.85%	-$20.98	$1.05	$1.11	$1.40	$1.48	$54.38	$51.91
	Average	11.0%							

Notes and Sources:
a/ Value Line forecast of DPS growth adjusted for the time value of money. See PGE Exhibit 2001/1.
b/ Average of range of analysts' forecasts from PGE Exhibit 2002/1.
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.
e/ Not included due to pending merger with FirstEnergy.

Portland General Electric

PGE Exhibit 2006 (page 2)
Update of PGE Exhibit 1210 using Mr. Storm's Sample

Alternative Multi-Stage DCF Growth Analysis

		Internal Rate of Return	P_0	First Year Dividend D_1[a/]	Stage 1[b/]		Stage 2 and 3[c,d/]		
				D_{2010}	D_{2011}	D_{2015}	D_{2016}	$(P+D)_{2025}$	P_{2025}[d/]
1	ALLETE, Inc.	10.60%	-$35.39	$1.83	$1.93	$2.37	$2.50	$86.53	$82.44
2	American Electric Power Co.	10.65%	-$31.63	$1.75	$1.82	$2.12	$2.20	$78.65	$75.21
3	Cleco Corporation	10.31%	-$26.60	$1.04	$1.12	$1.51	$1.62	$70.85	$67.97
4	Empire District Electric Co.	13.21%	-$18.79	$1.33	$1.42	$1.82	$1.94	$50.58	$47.28
5	IDACORP, Inc.	9.25%	-$34.08	$1.25	$1.31	$1.59	$1.67	$85.85	$83.15
6	PG&E Corporation	11.07%	-$39.98	$1.93	$2.07	$2.71	$2.90	$106.21	$101.19
7	Pinnacle West Capital Corp.	12.21%	-$35.71	$2.18	$2.32	$2.99	$3.18	$95.06	$89.65
8	Progress Energy Inc.	11.63%	-$38.91	$2.58	$2.68	$3.12	$3.24	$96.89	$91.84
9	TECO Energy, Inc.	11.76%	-$15.91	$0.86	$0.92	$1.22	$1.31	$42.80	$40.52
10	UIL Holdings	11.63%	-$27.06	$1.80	$1.87	$2.17	$2.26	$67.30	$63.79
11	Westar Energy, Inc.	12.40%	-$22.52	$1.29	$1.39	$1.89	$2.04	$62.15	$58.51
12	Wisconsin Energy Corp	10.10%	-$50.32	$1.72	$1.87	$2.63	$2.86	$136.14	$130.85
13	Xcel Energy Inc.	10.85%	-$20.98	$1.05	$1.11	$1.40	$1.48	$54.38	$51.91
	Average	11.2%							

Notes and Sources:
a/ Value Line forecast of DPS growth adjusted for the time value of money. See PGE Exhibit 2001/2.
b/ Average of range of analysts' forecasts from PGE Exhibit 2002/2.
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.

Portland General Electric

PGE Exhibit 2006 (page 3)
Update of PGE Exhibit 1210 using Mr. Storm's Sample,
Mr. Storm's Stock Prices (P_0) and First Year Dividends (D_1)

Alternative Multi-Stage DCF Growth Analysis

		Internal Rate of Return		First Year Dividend D_1[a]	Stage 1[b]		Stage 2 and 3[c,d]		
			P_0[a]	D_{2010}	D_{2011}[a]	D_{2015}	D_{2016}	$(P+D)_{2025}$	P_{2025}[d]
1	ALLETE, Inc.	10.52%	-$34.45	$1.76	$1.76	$2.17	$2.28	$87.93	$84.18
2	American Electric Power Co.	9.88%	-$34.26	$1.64	$1.66	$1.94	$2.02	$84.95	$81.80
3	Cleco Corporation	10.18%	-$26.89	$0.98	$1.10	$1.48	$1.59	$71.59	$68.76
4	Empire District Electric Co.	12.69%	-$18.33	$1.28	$1.28	$1.65	$1.75	$48.91	$45.92
5	IDACORP, Inc.	9.02%	-$35.21	$1.20	$1.26	$1.53	$1.61	$88.59	$85.99
6	PG&E Corporation	10.39%	-$42.78	$1.80	$1.92	$2.52	$2.70	$112.67	$108.00
7	Pinnacle West Capital Corp.	11.29%	-$38.37	$2.10	$2.13	$2.74	$2.92	$100.91	$95.95
8	Progress Energy Inc.	11.19%	-$39.56	$2.50	$2.52	$2.93	$3.05	$98.22	$93.48
9	TECO Energy, Inc.	11.00%	-$16.25	$0.80	$0.82	$1.08	$1.16	$43.20	$41.19
10	UIL Holdings	10.95%	-$28.36	$1.73	$1.73	$2.01	$2.09	$70.26	$67.01
11	Westar Energy, Inc.	11.84%	-$22.77	$1.24	$1.28	$1.74	$1.87	$62.19	$58.85
12	Wisconsin Energy Corp	9.94%	-$50.44	$1.60	$1.80	$2.54	$2.76	$136.17	$131.07
13	Xcel Energy Inc.	10.38%	-$21.52	$1.00	$1.03	$1.30	$1.37	$55.49	$53.20
	Average	10.7%							

Notes and Sources:
a/ Use Mr. Storm's prices and dividends for 2010 and 2011. Eliminate time value of money.
b/ Stage 1 growth based on average of analysts' forecasts from PGE Exhibit 2002/2.
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.

Portland General Electric

PGE Exhibit 2007
Update of PGE Exhibit 1211

Forecasts of Treasury and Baa Corporate Bond Rates

	2011	2012	2013	Average
Long-term Treasury Rates				
Blue Chip Consensus Forecasts[a/]	5.20%	5.30%	5.70%	
Value Line[b/]	4.90%	5.20%	5.60%	
Global Insight[c/]	4.92%	5.03%	5.23%	
Average	5.01%	5.18%	5.51%	5.23%
Baa Corporate Bond Rates				
Blue Chip Consensus Forecasts[a/]	6.90%	7.00%	7.50%	
Value Line[b/]	na	na	na	
Global Insight[c/]	6.70%	7.08%	7.22%	
Average	6.80%	7.04%	7.36%	7.07%

Notes and Sources:
a/ June 2010 Blue Chip long-term consensus forecasts.
b/ Value Line Quarterly forecasts dated May 28, 2010.
c/ April 2010 IHS Global Insight forecasts.

Portland General Electric

PGE Exhibit 2008
Update of PGE Exhibit 1212

**Risk Premium Analysis:
Method Used by Department of Ratepayer Advocates of the
California PUC[a/] with Data for Prior Oregon PUC Sample[b/]
2000 to 2009**

	Return on Equity[b/]	Baa Corporate Bond Rates[c/]	Average Annual Risk Premiums
2000	10.92%	8.37%	2.55%
2001	11.59%	7.95%	3.64%
2002	10.69%	7.80%	2.89%
2003	10.96%	6.76%	4.20%
2004	10.40%	6.39%	4.01%
2005	10.49%	6.06%	4.43%
2006	10.95%	6.48%	4.47%
2007	10.96%	6.48%	4.48%
2008	10.73%	7.44%	3.29%
2009	10.27%	7.29%	2.98%
	10-Year Average	7.10%	3.69%
	5-year Average	6.75%	3.93%
	Expected Baa Rate for 2011-2013[d/]		7.07%
	Projected Returns on Equity for Sample		
	10-Year Average		10.8%
	5-Year Average		11.0%
	Indicated Average Cost of Equity for PGE		11.1%

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 surviving utilities relied upon by the Oregon PUC to determine equity costs for electric utilities sample in UE 180.
c/ As reported by the Federal Reserve.
d/ Source is PGE Exhibit 2007.

Portland General Electric

PGE Exhibit 2009
Update of PGE Exhibit 1213

Risk Premium Analysis Based on Moody's Index and Updates

	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%

	Baa Corporate Bond Rate[a]	Year-end Price Index[b]	Annual Average Dividend[b]	Index Gain/Loss	Dividend Yield	Total Return	Risk Premium
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%	$216.86	$7.94	-4.51%	3.50%	-1.01%	-9.03%
2002	7.45%	$205.86	$8.08	-5.07%	3.73%	-1.35%	-9.40%
2003	6.60%	$208.10	$8.22	1.09%	3.99%	5.08%	-2.37%
2004	6.15%	$248.40	$8.41	19.36%	4.04%	23.40%	16.80%
2005	6.32%	$268.58	$8.84	8.12%	3.56%	11.68%	5.53%
2006	6.22%	$302.68	$9.05	12.70%	3.37%	16.07%	9.75%
2007	6.65%	$329.49	$9.42	8.86%	3.11%	11.97%	5.75%
2008	8.43%	$239.67	$9.92	-27.26%	3.01%	-24.25%	-30.90%
2009	--	$255.78	$10.11	6.72%	4.22%	10.94%	2.51%

	Updated Study	Original Study
Average Baa rate	7.9%	8.1%
Unadjusted risk premium	3.3%	4.2%
Expected Baa bond rate	7.1%	7.1%
Adjusted risk premium[c]	3.8%	4.7%
Estimated cost of equity for benchmark sar	10.8%	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 2001-2009.
c/ As explained in testimony, adjustment assumes equity costs change by 50% as much as interest rates.

Portland General Electric

PGE Exhibit 2010
Update of PGE Exhibit 1214

**Risk Premiums Determined by Relationship Between
Authorized ROEs and Baa Corporate Bond Rates[a]
During the Period 1985-2008**

Regression Output:

Constant (A_0)		0.0652
Std Err of Y Est		0.0072
R Squared		58.2%
No. of Observations		491
Degrees of Freedom		489
X Coefficient (A_1)	-0.3931	
Std Err of Coef.	0.0151	
t-statistic	-26.0772	

Equity Cost Estimate for Typical Electric Utility		Predicted Risk Premium		Expected Baa Bond Rate[b]
10.8%	=	3.74%	+	7.07%

Formula: Risk Premium = A_0 + (A_1 x Baa bond Rate)[c]

Notes and Sources:

_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 1999-2008.

_b/ Average of forecasts for 2011 to 2013 reported in PGE Exhibit 2007.

_c/ 6-month lag between order dates and Baa bond rates adopted.

Portland General Electric

PGE Exhibit 2011 (page 1)
Update of PGE Exhibit 1216

Summary Table: Updated Estimated Costs of Equity for Benchmark Samples and PGE

	Estimated Equity Costs for Benchmark Utilities			Estimated Equity Costs for PGE[n/]		
DCF Analyses						
DCF analysis -- Exhibit 2003/1		11.1%			11.3%	
DCF analysis -- Exhibit 2005/1		11.2%			11.4%	
DCF analysis -- Exhibit 2006/1		11.0%			11.2%	
Average of DCF Estimates		11.1%			11.30%	
Risk Premium analyses						
Risk premium -- Exhbit 2008	10.8%	to	11.0%	11.0%	to	11.2%
Risk Premium -- Exhbit 2009	10.8%	to	11.7%	11.0%	to	11.9%
Risk premium -- Exhibit 2010		10.8%			11.0%	
Average of RP Estimates		11.03%			11.23%	
Average of Equity Cost Estimates		11.07%			11.27%	

Notes and Sources:
n/ Equity Cost estimates include a 20 basis point risk premium for PGE.

Portland General Electric

PGE Exhibit 2011 (page 2)

Summary Table: Restatement of DCF Estimates Using Mr. Storm's Sample

	Estimated Equity Costs for Benchmark Utilities			Estimated Equity Costs for PGE[n/]		
DCF Analyses						
DCF analysis -- Exhibit 2003/2		11.5%			11.7%	
DCF analysis -- Exhibit 2005/2		11.4%			11.6%	
DCF analysis -- Exhibit 2006/2		11.2%			11.4%	
Range of Equity Cost Estimates	11.2%	to	11.5%	11.4%	to	11.7%
Average of Equity Cost Estimates		11.4%			11.6%	

Notes and Sources:
n/ Equity Cost estimates include a 20 basis point risk premium for PGE.

Portland General Electric

PGE Exhibit 2012

Perspective for ROEs and Estimated Equity Costs
Proposed by Staff, ICNU-CUB and PGE

Year	Authorized ROE[a/] (%)	Number of Rate Case Decisions[b/]
2010	10.58	5
2009	10.68	15
2008	10.58	12
2007	10.41	16
2006	10.87	7
2005	10.69	14
2005-2010	10.61	69

Precentage of Authorized ROEs greater than 9.2% [c/]	100%
Precentage of Authorized ROEs greater than 9.7% [d/]	100%
Precentage of Authorized ROEs greater than 10.5% [e/]	64%
Precentage of Authorized ROEs greater than 11.07% [f/]	10%

Notes and Sources:
a/ As reported by Regulatory Research Associates.
b/ Litigated decisions for vertically-integrated electric utilties that were not penalized by a reduction in authorized ROE.
c/ As proposed by Mr. Storm.
d/ As proposed by Mr. Gorman.
e/ As requested by PGE.
f/ Average equity cost estimated by Dr. Zepp.

Portland General Electric

PGE Exhibit 2013

Restatement of Mr. Storm's Analysis: Revise growth rates in 2012 to 2015 leave others the same

		Recent Price (1)	Value Line DPS Forecasts 2010 (2)	2011 (3)	Adopt Value Line EPS Forecasts for 2012 to 2015 2012 (4)	2013 (5)	2014 (6)	2015 (7)	2016-20 Dividend Growth Rate (8)	2021-49 Dividend Growth Rate (9)	2049 Terminal Value (10)	Internal Rate of Return (11)
1	Allete	$34.45	$1.76	$1.76	$1.85	$1.95	$2.06	$2.17	3.42%	4.30%	$177.23	9.2%
2	American Electric Power Co. Inc.	$34.26	$1.64	$1.66	$1.73	$1.79	$1.86	$1.94	3.42%	4.30%	$175.36	8.7%
3	Cleco Corp.	$26.89	$0.98	$1.10	$1.19	$1.28	$1.38	$1.48	3.42%	4.30%	$140.92	8.5%
4	Empire District Electric Co.	$18.33	$1.28	$1.28	$1.36	$1.45	$1.55	$1.65	3.42%	4.30%	$94.56	11.3%
5	IDACORP, Inc.	$35.21	$1.20	$1.26	$1.33	$1.39	$1.46	$1.53	3.42%	4.30%	$182.48	7.7%
6	PG&E Corp.	$42.78	$1.80	$1.92	$2.06	$2.20	$2.36	$2.52	3.42%	4.30%	$222.88	8.8%
7	Pinnacle West	$38.37	$2.10	$2.13	$2.27	$2.42	$2.58	$2.74	3.42%	4.30%	$198.51	9.8%
8	Progress Energy Inc.	$39.56	$2.50	$2.52	$2.62	$2.72	$2.82	$2.93	3.42%	4.30%	$200.92	10.1%
9	TECO Energy, Inc.	$16.25	$0.80	$0.82	$0.88	$0.94	$1.01	$1.08	3.42%	4.30%	$84.51	9.4%
10	UIL Holdings	$28.36	$1.73	$1.73	$1.80	$1.86	$1.94	$2.01	3.42%	4.30%	$144.08	9.9%
11	Westar Energy Inc.	$22.77	$1.24	$1.28	$1.38	$1.49	$1.61	$1.74	3.42%	4.30%	$118.90	10.2%
12	Wisconsin Energy Corporation	$50.44	$1.60	$1.80	$1.96	$2.14	$2.33	$2.54	3.42%	4.30%	$265.81	8.1%
13	Xcel Energy	$21.52	$1.00	$1.03	$1.09	$1.16	$1.23	$1.30	3.42%	4.30%	$111.29	9.0%
	Group Average											9.3%

Notes and Sources:
Mr. Storm's work papers and Value Line EPS forecasts (see PGE Exhibit 2002/2).

Portland General Electric

PGE Exhibit 2014

**Comparison of Current Average of Analysts' Forecast to Data
Provided in UE 197/PGE Exhibit 1003**

		Current Average of Analysts' Forecasts[c/]	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	6.1	5.0	9.0	7.0	7.0
2	Alliant Energy	7.0	6.0	5.0	4.0	7.0
3	Ameren	2.5	7.0	4.0	5.0	4.0
4	Amer Elect Pwr	3.9	6.0	4.0	4.0	4.0
5	Central Vermont	_b/	_b/	_b/	_b/	_b/
6	CLECO	7.8	12.0	11.0	5.0	4.0
7	DPL Inc	7.3	6.0	7.0	5.0	5.0
8	DTE Energy	5.4	6.0	5.0	6.0	6.0
9	Duke	3.1	5.0	6.0	6.0	4.0
10	Edison International	2.6	7.0	7.0	7.0	5.0
11	Empire District	6.5	19.0	6.0	2.0	3.0
12	Entergy	6.7	10.0	8.0	7.0	5.0
13	FPL Group	6.3	9.0	8.0	6.0	5.0
14	Hawaiian	9.1	2.0	3.0	4.0	3.0
15	IDACORP	5.0	6.0	5.0	4.0	na
16	PG&E	7.0	9.0	8.0	5.0	6.0
17	Pinnacle West	6.5	6.0	5.0	6.0	5.0
18	PNM Resources	_b/	_b/	_b/	_b/	_b/
19	Portland General	_b/	_b/	_b/	_b/	_b/
20	PPL	_b/	_b/	_b/	_b/	_b/
21	Progress Energy	3.9	5.0	4.0	4.0	5.0
22	Southern Company	4.9	5.0	3.0	7.0	5.0
23	TECO	7.2	3.0	3.0	7.0	4.0
24	Westar	7.9	5.0	6.0	3.0	4.0
25	Wisconsin Energy	9.0	9.0	8	8.0	5.0
26	Xcel Energy	5.9	6.0	6.4	5.7	4.8
	Average	6.0	7.0	6.0	5.3	4.8

Notes and Sources:

a/ Sources of data for UE 197/PGE Exhbit 1003 are indicated copies of the S&P Earnings Guide (which is no longer published by S&P).

b/ Data not included since data not available for both studies.

c/ Averages of growth rates reported in PGE Exhibit 2002/1 (update of PGE Exhibit 1206).

Portland General Electric

PGE Exhibit 2015

Revise Growth in 2012-2015 and adopt Mr. Storm's GDP Forecasts of 4.75% and 5.86%

		Recent Price (1)	Value Line DPS Forecasts 2010 (2)	2011 (3)	Adopt Value Line EPS Forecasts for 2012 to 2015 2012 (4)	2013 (5)	2014 (6)	2015 (7)	2016-20 Dividend Growth Rate (8)	2021-49 Dividend Growth Rate (9)	2049 Terminal Value (10)	Internal Rate of Return (11)
1	Allete	$34.45	$1.76	$1.76	$1.85	$1.95	$2.06	$2.17	4.75%	5.86%	$311.33	10.4%
2	American Electric Power Co. Inc.	$34.26	$1.64	$1.66	$1.73	$1.79	$1.86	$1.94	4.75%	5.86%	$310.28	9.9%
3	Cleco Corp.	$26.89	$0.98	$1.10	$1.19	$1.28	$1.38	$1.48	4.75%	5.86%	$250.49	9.8%
4	Empire District Electric Co.	$18.33	$1.28	$1.28	$1.36	$1.45	$1.55	$1.65	4.75%	5.86%	$167.10	12.4%
5	IDACORP, Inc.	$35.21	$1.20	$1.26	$1.33	$1.39	$1.46	$1.53	4.75%	5.86%	$325.74	9.0%
6	PG&E Corp.	$42.78	$1.80	$1.92	$2.06	$2.20	$2.36	$2.52	4.75%	5.86%	$395.42	10.1%
7	Pinnacle West	$38.37	$2.10	$2.13	$2.27	$2.42	$2.58	$2.74	4.75%	5.86%	$350.54	11.0%
8	Progress Energy Inc.	$39.56	$2.50	$2.52	$2.62	$2.72	$2.82	$2.93	4.75%	5.86%	$354.46	11.3%
9	TECO Energy, Inc.	$16.25	$0.80	$0.82	$0.88	$0.94	$1.01	$1.08	4.75%	5.86%	$150.20	10.6%
10	UIL Holdings	$28.36	$1.73	$1.73	$1.80	$1.86	$1.94	$2.01	4.75%	5.86%	$253.82	11.0%
11	Westar Energy Inc.	$22.77	$1.24	$1.28	$1.38	$1.49	$1.61	$1.74	4.75%	5.86%	$209.54	11.3%
12	Wisconsin Energy Corporation	$50.44	$1.60	$1.80	$1.96	$2.14	$2.33	$2.54	4.75%	5.86%	$471.24	9.4%
13	Xcel Energy	$21.52	$1.00	$1.03	$1.09	$1.16	$1.23	$1.30	4.75%	5.86%	$197.11	10.2%
	Group Average											10.5%
	Recognize Time Value of Money											10.7%

Notes and Sources:
Mr. Storm's work papers, Value Line EPS forecasts (see PGE Exhibit 2002/2) and Staff Exhibit 900, page 66.

Portland General Electric

PGE Exhibit 2016

**Examination of Bias in Real and Nominal Value Line ROE Forecasts for 8 Natural Gas Utilities
1977 to 1998**

		Nominal Returns			Inflation [c/]			Real Returns		
	Date of Value Line Issue	Average Value Line Forecasted ROE (1977-1994)	Average Actual Earned ROE 4 Years Later (1981-1998)	Difference Between Forecasted and Actual Nominal ROEs	Expected Inflation	Actual Inflation	Difference Between Forecasted and Actual Inflation	Average Value Line Forecasted ROE (1977-1994)	Actual Earned ROE 4 Years Later (1981-1998)	Difference Between Forecasted and Actual Real ROEs
1	Oct-77	13.00%	11.32%	1.68%	5.50%	9.70%	-4.20%	7.50%	1.62%	5.88%
2	Jan-79	12.81%	11.91%	0.90%	5.50%	3.90%	1.60%	7.31%	8.01%	-0.70%
3	Oct-80	14.13%	15.86%	-1.73%	8.25%	3.70%	4.55%	5.88%	12.16%	-6.28%
4	Oct-81	15.06%	13.81%	1.25%	7.50%	3.20%	4.30%	7.56%	10.61%	-3.05%
5	Oct-82	14.00%	12.07%	1.93%	5.20%	2.60%	2.60%	8.80%	9.47%	-0.67%
6	Oct-83	13.94%	12.28%	1.66%	5.00%	3.00%	2.00%	8.94%	9.28%	-0.34%
7	Oct-84	15.13%	14.67%	0.46%	5.50%	3.70%	1.80%	9.63%	10.97%	-1.34%
8	Oct-85	15.56%	13.12%	2.44%	4.50%	4.20%	0.30%	11.06%	8.92%	2.14%
9	Oct-86	13.63%	12.41%	1.21%	3.80%	4.40%	-0.60%	9.83%	8.01%	1.81%
10	Oct-87	13.19%	11.62%	1.56%	4.50%	4.00%	0.50%	8.69%	7.62%	1.06%
11	Oct-88	13.13%	10.88%	2.24%	4.60%	2.70%	1.90%	8.53%	8.18%	0.34%
12	Oct-89	13.50%	12.58%	0.92%	4.60%	2.60%	2.00%	8.90%	9.98%	-1.08%
13	Oct-90	14.00%	11.71%	2.29%	4.30%	2.30%	2.00%	9.70%	9.41%	0.29%
14	Oct-91	14.13%	11.34%	2.78%	3.70%	2.50%	1.20%	10.43%	8.84%	1.58%
15	Oct-92	14.38%	13.08%	1.29%	3.90%	2.10%	1.80%	10.48%	10.98%	-0.51%
16	Dec-93	12.56%	12.62%	-0.06%	2.40%	2.00%	0.40%	10.16%	10.62%	-0.46%
17	Dec-94	12.19%	11.20%	0.99%	2.80%	1.30%	1.50%	9.39%	9.90%	-0.51%
	Average	13.78%	12.50%	1.28%	4.80%	3.41%	1.39%	8.99%	9.09%	-0.11%

Notes and Sources:
a/ Source of Study: Testimony of T. Zepp in Oregon PUC Docket UG 132, Exhibit UG 132/NWN/5000.
b/ ROEs are annual averages for 8 natural gas distribution companies for each year.
c/ Based on forecasted and realized values for the GNP deflator.

Portland General Electric

PGE Exhibit 2017

Rebuttal of Mr. Gorman's Equity Cost Estimates

	Median[e/] Reported by Mr. Gorman	Mean Reported by Mr. Gorman	Restatement
Constant Growth DCF model	10.80%	10.75%	10.90% [a/]
Sustainable Growth	9.54%	9.92%	nmf [b/]
Multi-stage DCF model	10.03%	10.02%	10.31% [c/]
CAPM	9.50%	9.50%	10.31% [d/]
Average	9.97%	10.05%	10.51%

Notes and Sources:

a/ Add Yahoo! Finance growth rate estimates to average of growth rates.
b/ No simple update is possible. As formulated by Mr. Gorman, this model is internally inconsistent with the 10.95% ROE assumed to be earned.
c/ Adopt average of Blue Chip and Value Line forecasts of GDP growth.
d/ Revised MRP estimate based on Morningstar's long-term average of 6.7% and MRP implied by Value Line forecasts for the Industrial Composit for last ten years.
e/ Mr. Gorman recommends reliance on medians instead of means.

Portland General Electric Company

PGE Exhibit 2018

Restatement of Mr. Gorman's Sustainable Constant Growth DCF Model

		13-Week AVG Stock Price (1)	Sustainable Growth (2)	Annualized Dividend (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Allegheny Energy, Inc.	$22.65	8.07%	$0.60	2.86%	10.93%
2	ALLETE, Inc.	$33.88	3.20%	$1.76	5.36%	8.57%
3	Alliant Energy Corporation	$33.02	5.83%	$1.58	5.06%	10.89%
4	Ameren Corporation		nmf			nmf
5	American Electric Power Co.	$33.77	4.86%	$1.64	5.09%	9.95%
6	Avista Corporation	$20.96	3.30%	$1.00	4.93%	8.23%
7	Cleco Corporation	$26.34	5.54%	$1.00	4.01%	9.55%
8	CMS Energy Corporation	$15.60	5.11%	$0.60	4.04%	9.16%
9	DPL Inc.	$27.23	15.10%	$1.21	5.12%	20.22%
10	DTE Energy Company	$45.09	3.90%	$2.12	4.89%	8.79%
11	Duke Energy Corporation		nmf			nmf
12	Edison International	$33.76	5.23%	$1.26	3.93%	9.16%
13	Empire District Electric Co.	$18.46	2.67%	$1.28	7.12%	9.79%
14	Entergy Corporation		nmf			nmf
15	FPL Group, Inc.	$48.36	6.02%	$2.00	4.38%	10.41%
16	Great Plains Energy Incorporated		nmf			nmf
17	Hawaiian Electric Industries, Inc.	$21.88	4.35%	$1.24	5.91%	10.27%
18	IDACORP, Inc.	$34.43	5.06%	$1.20	3.66%	8.72%
19	MGE Energy, Inc.	$35.00	5.24%	$1.47	4.43%	9.67%
20	Northwestern Corporation		na			na
21	OGE Energy Corp.	$38.36	7.58%	$1.45	4.07%	11.65%
22	PG&E Corporation	$42.44	6.50%	$1.82	4.57%	11.07%
23	Pinnacle West Capital Corp.	$37.23	3.69%	$2.10	5.85%	9.54%
24	Portland General Electric		nmf			nmf
25	Progress Energy Inc.	$38.97	2.62%	$2.48	6.53%	9.15%
26	Southern Company	$32.99	5.37%	$1.75	5.60%	10.96%
27	TECO Energy, Inc.	$15.90	5.63%	$0.80	5.31%	10.94%
28	UniSource Energy Corporation	$31.63	5.30%	$1.56	5.19%	10.49%
29	Westar Energy, Inc.	$22.28	3.37%	$1.24	5.75%	9.12%
30	Wisconsin Energy Corporation	$50.03	6.01%	$1.60	3.39%	9.40%
31	Xcel Energy Inc.	$21.18	4.89%	$0.98	4.85%	9.75%
32	**Average**	**$31.26**	**5.38%**	**$1.43**	**4.88%**	**10.25%**
33	**Median**					**9.75%**

Notes and Sources:
ICNU-CUB Exhibit 210 and ICNU-CUB Exhibit 211.

Portland General Electric

PGE Exhibit 2019

Market Risk Premium Implied by Analysis of Value Line's Industrial Composite

	Study Date	Dividend Yield	Average of EPS and BR growth	DCF Equity Cost	Long-term Treasury Lag 1 Mnth	Risk Premium
1	1/85	3.80%	12.06%	15.86%	11.52%	4.34%
2	1/86	3.80%	10.11%	13.91%	9.54%	4.37%
3	2/87	3.00%	9.48%	12.48%	7.39%	5.09%
4	2/88	3.10%	11.25%	14.35%	8.83%	5.52%
5	7/88	3.50%	8.26%	11.76%	9.00%	2.76%
6	2/89	3.50%	10.01%	13.51%	8.93%	4.58%
7	2/90	3.20%	7.88%	11.08%	8.26%	2.82%
8	1/91	3.70%	9.08%	12.78%	8.24%	4.54%
9	2/92	2.80%	10.06%	12.86%	7.58%	5.28%
10	2/93	2.90%	7.69%	10.59%	7.34%	3.25%
11	2/94	3.00%	10.87%	13.87%	6.39%	7.48%
12	2/95	2.70%	11.25%	13.95%	7.97%	5.98%
13	3/96	2.70%	12.49%	15.19%	6.03%	9.16%
14	2/97	2.40%	11.96%	14.36%	6.91%	7.45%
15	1/98	1.50%	12.95%	14.45%	6.07%	8.38%
16	1/99	1.30%	13.81%	15.11%	5.36%	9.75%
17	2/00	0.80%	12.58%	13.38%	6.86%	6.52%
18	7/00	1.00%	12.49%	13.49%	6.28%	7.21%
19	2/01	1.20%	10.76%	11.96%	5.65%	6.31%
20	7/01	1.20%	10.07%	11.27%	5.82%	5.45%
21	1/02	1.20%	8.96%	10.16%	5.76%	4.40%
22	8/02	1.60%	7.85%	9.45%	5.51%	3.94%
23	1/03	1.60%	7.41%	9.01%	5.01%	4.00%
24	7/03	1.50%	9.92%	11.42%	4.34%	7.08%
25	3/04	1.60%	9.27%	10.87%	4.94%	5.93%
26	10/04	1.80%	9.57%	11.37%	4.89%	6.48%
27	4/05	1.90%	8.95%	10.85%	4.89%	5.96%
28	11/05	2.10%	11.03%	13.13%	4.74%	8.39%
29	5/06	2.10%	9.28%	11.38%	5.22%	6.16%
30	11/06	2.20%	12.03%	14.23%	4.94%	9.29%
31	5/07	2.50%	11.13%	13.63%	4.87%	8.76%
32	11/07	1.60%	11.93%	13.53%	4.77%	8.76%
33	5/08	1.80%	14.08%	15.88%	4.44%	11.44%
34	11/08	2.80%	11.89%	14.69%	4.17%	10.52%
35	5/09	2.80%	12.70%	15.50%	3.76%	11.74%
36	11/09	2.40%	11.22%	13.62%	4.19%	9.43%

Averages for:

All years	6.6%
Last 10 years (2000-2009)	7.4%
Last 5 years (2005-2009)	9.0%

Portland General Electric

PGE Exhibit 2020

Rebuttal of Mr. Gorman's Restatements of Dr. Zepp's Equity Cost Estimates

	Restatement Reported by Mr. Gorman	Correct Errors		Revise Restatement	
Constant Growth DCF model	10.9%	10.9%		10.9%	a/
FERC DCF model	10.3%	10.3%		10.7%	b/
Multi-stage DCF model	9.6%	10.1%	c/	10.5%	d/
Average	10.3%	10.4%		10.7%	

Notes and Sources:
a/ No revision in Mr. Gorman's restatement.
b/ Eliminate arbitrary constraint on high growth rate estimates.
c/ Fix error in the program Mr. Gorman used. He inserted percentage growth rates (which become only pennies of cash flow) to be the first positive cash flow for each stock thus creating a serious negative bias in the estimates of internal rates of return.
d/ To be conservative adopt Value Line's GDP forecast of 5.47% instead of 5.8% GDP growth for last stage.

NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

Appendix 4-A
Arithmetic versus Geometric Means in Estimating the Cost of Capital

The use of the arithmetic mean appears counter-intuitive at first glance, because we commonly use the geometric mean return to measure the average annual achieved return over some time period. For example, the long-term performance of a portfolio is frequently assessed using the geometric mean return.

But performance appraisal is one thing, and cost of capital estimation is another matter entirely. In estimating the cost of capital, the goal is to obtain the rate of return that investors expect, that is, a target rate of return. On average, investors expect to achieve their target return. This target expected return is in effect an arithmetic average. The achieved or retrospective return is the geometric average. In statistical parlance, the arithmetic average is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean. This appendix formally illustrates that only arithmetic averages can be used as estimates of cost of capital, and that the geometric mean is not an appropriate measure of cost of capital.

The geometric mean answers the question of what constant return you would have had to achieve in each year to have your investment growth match the return achieved by the stock market. The arithmetic mean answers the question of what growth rate is the best estimate of the future amount of money that will be produced by continually reinvesting in the stock market. It is the rate of return which, compounded over multiple periods, gives the mean of the probability distribution of ending wealth.

While the geometric mean is the best estimate of performance over a long period of time, this does not contradict the statement that the arithmetic mean compounded over the number of years that an investment is held provides the best estimate of the ending wealth value of the investment. The reason is that an investment with uncertain returns will have a higher ending wealth value than an investment which simply earns (with certainty) its compound or geometric rate of return every year. In other words, more money, or terminal wealth, is gained by the occurrence of higher than expected returns than is lost by lower than expected returns.

In capital markets, where returns are a probability distribution, the answer that takes account of uncertainty, the arithmetic mean, is the correct one for estimating discount rates and the cost of capital.

While the geometric mean is appropriate when measuring performance over a long time period, it is incorrect when estimating a risk premium to compute the cost of capital.

TABLE 4A-1
GEOMETRIC VS. ARITHMETIC RETURNS

	Stock A	Stock B
1996	50.0%	11.61%
1997	−54.7%	11.61%
1998	98.5%	11.61%
1999	42.2%	11.61%
2000	−32.3%	11.61%
2001	−39.2%	11.61%
2002	153.2%	11.61%
2003	−10.0%	11.61%
2004	38.9%	11.61%
2005	20.0%	11.61%
Standard Deviation	64.9%	0.0%
Arithmetic Mean	26.7%	11.6%
Geometric Mean	11.6%	11.6%

Theory

The geometric mean measures the magnitude of the returns, as the investor starts with one portfolio and ends with another. It does not measure the variability of the journey, as does the arithmetic mean. The geometric mean is backward looking. There is no difference in the geometric mean of two stocks or portfolios, one of which is highly volatile and the other of which is absolutely stable. The arithmetic mean, on the other hand, is forward-looking in that it does impound the volatility of the stocks.

To illustrate, Table 4A-1 shows the historical returns of two stocks, the first one is highly volatile with a standard deviation of returns of 65% while the second one has a zero standard deviation. It makes no sense intuitively that the geometric mean is the correct measure of return, one that implies that both stocks are equally risky since they have the same geometric mean. No rational investor would consider the first stock equally as risky as the second stock. Every financial model to calculate the cost of capital recognizes that investors are risk-averse and avoid risk unless they are adequately compensated for undertaking it. It is more consistent to use the mean that fully impounds risk (arithmetic mean) than the one from which risk has been removed (geometric mean). In short, the arithmetic mean recognizes the uncertainty in the stock market while the geometric mean removes the uncertainty by smoothing over annual differences.

Empirical Evidence

If both the geometric and arithmetic mean returns over the 1926–2004 data are regressed against the standard deviation of returns for the firms in the deciles, the arithmetic mean outperforms the geometric mean in this statistical regression. Moreover, the constant of arithmetic mean regression matches the average Treasury bond rate and therefore makes economic sense while the constant for the geometric mean matches nothing in particular. This is simply because the geometric mean is stripped of volatility information and, as a result, does a poor job of forecasting returns based on volatility.

The following illustration is frequently invoked in defense of the geometric mean. Suppose that a stock's performance over a two-year period is representative of the probability distribution, doubling in one year ($r_1 = 100\%$) and halving in the next ($r_2 = -50\%$). The stock's price ends up exactly where it started, and the geometric average annual return over the two-year period, r_g, is zero:

$$\begin{aligned} 1 + r_g &= [(1 + r_1)(1 + r_2)]^{1/2} \\ &= [(1 + 1)(1 - .50)]^{1/2} = 1 \\ r_g &= 0 \end{aligned}$$

confirming that a zero year-by-year return would have replicated the total return earned on the stock. The expected annual future rate of return on the stock is not zero, however. It is the arithmetic average of 100% and −50%, (100−50)/2 = 25%. There are two equally likely outcomes per dollar invested: either a gain of \$1 when r = 100% or a loss of \$0.50 when r = −50%. The expected profit is (\$1−\$.50)/2 = \$.25 for a 25% expected rate of return. The profit in the good year more than offsets the loss in the bad year, despite the fact that the geometric return is zero. The arithmetic average return thus provides the best guide to expected future returns.

What Academics Have to Say

Bodie, Kane, and Marcus (2005) cite:

> Which is the superior measure of investment performance, the arithmetic average or the geometric average? The geometric average has considerable appeal because it represents the constant rate of return we would have needed to earn in each year to match actual performance over some past investment period. It is an excellent measure of *past* performance. However, if our focus is on future performance, then the arithmetic average is the statistic of interest because it is an unbiased estimate of the portfolio's expected future return (assuming, of course, that the expected return does not change over time). In contrast, because the geometric return over a sample period is always less than the arithmetic mean,

> it constitutes a downward-biased estimator of the stock's expected return in any future year.
>
> Again, the arithmetic average is the better guide to future performance.

Another way of stating the Bodie, Kane, Marcus argument in favor of the arithmetic mean is that it is the best estimate of the future value of the return distribution because it represents the expected value of the distribution. It is most useful for determining the central tendency of a distribution at a particular time, that is, for cross-sectional analysis. The geometric mean, on the other hand, is best suited for measuring an investment's compound rate of return over time, that is, for time-series analysis. This is the same argument made by Ibbotson Associates (2005) where it is shown, using probability theory, that future terminal wealth is given by compounding the arithmetic mean, and not the geometric mean. In other words, if we accept the past as prologue, the best estimate of a future year's return based on a random distribution of the prior years' returns is the arithmetic average. Statistically, it is our best guess for the holding-period return in a given year.

Brigham and Ehrhardt (2005) in their widely used corporate finance text point out that the arithmetic average is more consistent with CAPM theory, as one of its key underpinning assumptions is that investors are supposed to focus, in their portfolio decisions, upon returns in the next period and the standard deviation of this return. To the extent that this next period is one year, the preference for the arithmetic mean, which derives from a set of single one year period returns, follows. It is also noteworthy that one of the crucial assumptions inherent in the CAPM is that investors are single-period expected utility of terminal wealth maximizers who choose among alternative portfolios on the basis of each portfolio's expected return and standard deviation.

Brealey, Myers, and Allen (2006) in their leading graduate textbook in corporate finance opt strongly for the arithmetic mean. The authors illustrate the distinction between arithmetic and geometric averages and conclude that arithmetic averages are appropriate when estimating the cost of capital:

> The proper uses of arithmetic and compound rates of return from past investments are often misunderstood. Therefore, we call a brief time-out for a clarifying example.
>
> Suppose that the price of Big Oil's common stock is \$100. There is an equal chance that at the end of the year the stock will be worth \$90, \$110, or \$130. Therefore, the return could be -10 percent, $+10$ percent or $+30$ percent (we assume that Big Oil does not pay a dividend). The expected return is $1/3(-10+10+30) = +10$ percent.

If we run the process in reverse and discount the expected cash flow by the expected rate of return, we obtain the value of Big Oil's stock:

$$PV = \frac{110}{1.10} = \$100$$

The expected return of 10 percent is therefore the correct rate at which to discount the expected cash flow from Big Oil's stock. It is also the opportunity cost of capital for investments which have the same degree of risk as Big Oil.

Now suppose that we observe the returns on Big Oil stock over a large number of years. If the odds are unchanged, the return will be -10 percent in a third of the years, $+10$ percent in a further third, and $+30$ percent in the remaining years. The arithmetic average of these yearly returns is

$$\frac{-10+10+30}{3} = +10\%$$

Thus the arithmetic average of the returns correctly measures the opportunity cost of capital for investments of similar risk to Big Oil stock.

The average compound annual return on Big Oil stock would be

$$(.9 \times 1.1 \times 1.3)^{1/3} - 1 = .088, \text{ or } 8.8\%$$

less than the opportunity cost of capital. Investors would not be willing to invest in a project that offered an 8.8 percent expected return if they could get an expected return of 10 percent in the capital markets. The net present value of such a project would be

$$NPV = -100 + \frac{108.8}{1.1} = -1.1$$

Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return (geometric averages).

(Richard A. Brealey, Stewart C. Myers, and Paul Allen, *Principles of Corporate Finance*, 8th Edition, Irwin McGraw-Hill, 2006, page 156–7.)

The widely cited Ibbotson Associates publication also contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital.[12]

[12] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, 2005 Yearbook, Valuation Edition*, page 75.

> The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.
>
> The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods.
>
> The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values.

In their widely publicized research on the market risk premium, Dimson, Marsh and Staunton (2002) state

> The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and −20 percent. Their arithmetic mean is 2½ percent, since (25 − 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) × (1 − 20/100) − 1 = 0. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.
>
> To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.015 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 × ½ + $0.80 × ½ = $1.00. If there were a sequence of equally likely returns of +25 and −20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns.

Lastly, on the practical side, Bruner, Eades, Harris, and Higgins (1998) found that 71% of the texts and tradebooks in their extensive survey of practice supported use of an arithmetic mean for estimation of the cost of equity.

Mean Reversion Argument

Some academics have argued that if stock returns were expected to revert to a trend, this would suggest the use of a geometric mean since the geometric mean is, by definition, an estimate of a smoothed long-run trend increment. These same academics have argued that the historical estimate of the market risk premium ("MRP") is upward-biased by the buoyant performance of the stock market prior to 2002, and because of the extraordinary and unusually high realized MRPs in those years, investors expect a return to lower MRPs in the future, bringing the average MPR to a more "normal" level.

The presence or absence of mean reversion is an empirical issue. The empirical findings are weak and highly contradictory; the empirical evidence is inconclusive and unconvincing, certainly not enough to support the "mean reversion" hypothesis. The weight of the empirical evidence on this issue is that the more sophisticated tests of mean reversion in the MRP demonstrate that the realized MRP over the last 75 years or so was almost perfectly free of mean reversion, and had no statistically identifiable time trend. It is also noteworthy that most of these studies were performed prior to the stock market's debacle in 2000–2002, years of extraordinary and unusually low realized MRPs. The stock market's dismal performance of 2000–2002 has certainly taken the wind out of the mean reversion school's sails.

An examination of historical MRPs reveals that the MRP is random with no observable pattern. To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Therefore, the best estimate of the future risk premium is the historical mean.

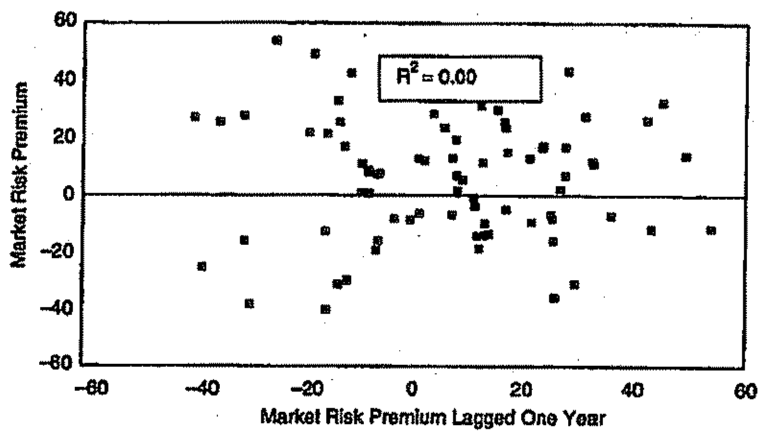
Ibbotson Associates (2005) find no evidence that the market price of risk or the amount of risk in common stocks has changed over time:

> Our own empirical evidence suggests that the yearly difference between the stock market total return and the U.S. Treasury bond income return in any particular year is random ... there is no discernable pattern in the realized equity risk premium. (Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, 2005 Yearbook, Valuation Edition,* pages 74–75)

In statistical parlance, there is no significant serial correlation in successive annual market risk premiums, that is, no trend. Ibbotson Associates go on to state that it is reasonable to assume that these quantities will remain stable in the future (*Id.*):

> The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean)

FIGURE 4A-1
MARKET RISK PREMIUM 1926–2004
Year-to-Year Correlation



of its past values. (Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, 2004 Yearbook, Valuation Edition*, page 75)

Nowhere is it suggested by Ibbotson Associates that the market risk premium has declined over time.

Because there is little evidence that the MRP has changed over time, it is reasonable to assume that these quantities will remain stable in the future. Figure 4A-1 shows the relationship, or the lack of relationship, between year-to-year MRPs reported in the Ibbotson Associates Valuation Yearbook, 2005 edition, for the 1926–2004 period. The relationship is virtually absent, as indicated by the low R^2 of zero between successive MRPs. In other words, there is no history in successive MRPs as indicated by the zero serial correlation coefficient.

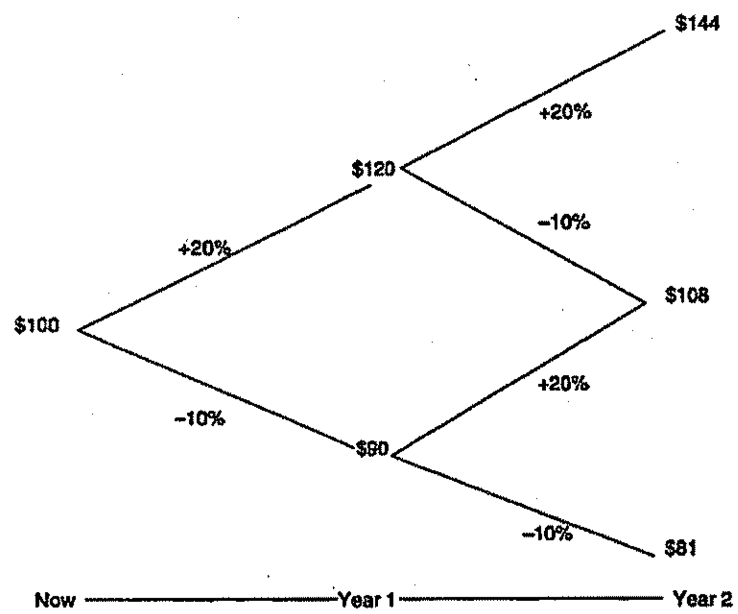
In short, the determination of the cost of capital with the CAPM requires an unbiased estimate of the expected annual return. The expected arithmetic return provides the appropriate measure for this purpose.

Formal Demonstration

This section shows why arithmetic rather than geometric means should be used for forecasting, discounting, and estimating the cost of capital.[13] By

[13] This section is adapted from a similar treatments and demonstration in Brealey, Myers, and Allen (2006) and Ibbotson Associates (2005).

FIGURE 4A-2
POSSIBLE STOCK PRICES



definition, the cost of equity capital is the annual discount rate that equates the discounted value of expected future cash flows (from dividends and the sale of the stock at the end of the investor's investment horizon) to the current market price of a share in the firm. The discount rate that equates the discounted value of future expected dividends and the end of period expected stock price to the current stock price is a prospective arithmetic, rather than a prospective geometric, mean rate of return. Since future dividends and stock prices cannot be predicted with certainty, the "expected" annual rate of return that investors require is an average "target" percentage rate around which the actual, year-by-year returns will vary. This target rate is, in effect, an arithmetic average.

A numerical illustration will clarify this important point. Consider a non-dividend paying stock trading for $100 which has, in every year, an equal chance of appreciating by 20% or declining by 10%. Thus, after one year, there is an equal chance that the stock's price will be $120 and an equal chance the price will be $90. Figure 4A-2 presents all possible eventualities after two periods have elapsed (the rates of return are presented at the end of the lines in the diagram).

The possible stock prices are shown in the following table.

TABLE 4A-2
STOCK PRICES AFTER TWO PERIODS

Price	Chance
$144	1 chance in 4
$108	2 chances in 4
$ 81	1 chance in 4

The expected future stock price after two periods is then:

$$1/4\ (\$144) + 2/4\ (\$108) + 1/4\ (\$81) = \$110.25$$

The cost of equity capital is calculated as the discount rate that equates the present value of the future expected cash flows to the current stock price. In the present simple example, the only cash flow is the gain from selling the stock after two periods have elapsed. Thus, using the expected stock price of $110.25 calculated above, the expected rate of return is that r, which solves the following equation:

$$\text{Current Stock Price} = \frac{\text{Expected Stock Price}}{(1 + r)^2}$$

The factor $(1 + r)^2$ discounts the expected stock price to the present. Substituting the numerical values, we have:

$$\$100 = \frac{\$110.25}{(1+r)^2}$$

$$r = 5\%$$

Thus, the cost of equity capital is 5%. This 5% cost of equity capital is equal to the prospective arithmetic mean rate of return, which is the probability-weighted average single period rate of return on equity. Since in every period there is an equal chance that the stock's return will be 20% or −10%, the probability-weighted average is:

$$1/2\ (20\%) + 1/2\ (-10\%) = 5\%$$

However, the 5% cost of equity capital is not equal to the prospective geometric mean rate of return, which is a probability-weighted average of the possible compounded rates of return over the two periods. Now consider the prospective geometric mean rate of return. Table 4A-3 shows the possible compounded rates of return over two periods, and the probability of each.

Thus, the prospective geometric mean rate of return is:

$$1/4\ (20\%) + 2/4\ (3.92\%) + 1/4\ (-10\%) = 4.46\%$$

TABLE 4A-3
STOCK PRICES AND RETURNS AFTER TWO PERIODS

Price	Chance	Compounded Return
$144	1 chance in 4	20.00%
$108	2 chances in 4	3.92%
$ 81	1 chance in 4	−10.00%

This return is not equal to the 5% cost of equity capital.

The example can easily be extended to include the case of a dividend-paying company and will reach the same conclusion: the implied discount rate calculated in the DCF model is an expected arithmetic rather than an expected geometric mean rate of return.

The foregoing analysis shows that it is erroneous to use a prospective multi-year geometric mean rate of return as a "target" rate of return for each year of the period. If, for example, investors currently require an expected future rate of return on an investment of 13% each year, then 13% is the appropriate annual rate of return on equity for ratemaking purposes. Consequently, in using a risk premium approach for the purposes of rate of return regulation, the single-year annual required rate of return should be estimated using arithmetic mean risk premiums.

It should be pointed out that the use of the arithmetic mean does not imply an investment holding period of one year. Rather, it is premised on the uncertainty with respect to each year's return during the holding period, however many years that may be. When computing the arithmetic average of historic annual returns in order to calculate the average return (expected value of the return), every achieved return outcome is one possible future outcome for each year the security will be held. Each historic return has an equal probability of occurring during each year of the holding period. The resulting expected value of the risk premium is the arithmetic average of all of the past premiums considered, regardless of the length of the expected holding period.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Doug Kuns
Marc Cody

July 19, 2010

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 name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department.

Q. Have you previously testified in this proceeding?

A. Yes, our qualifications are provided in PGE Exhibit 1500.

Q. What is the purpose of this rebuttal testimony?

A. We provide an update of the overall rate impacts and the impacts to various rate schedules consistent with the testimony in PGE Exhibit 1600 and the anticipated stipulation on ratespread and rate design entered into with OPUC Staff, CUB, ICNU, and Kroger. In addition, we address the issues identified by the City of Portland (COP), and the International Dark Sky Association. We also discuss the decoupling proposals of Staff and CUB.

Q. Please summarize the updated projected 2011 Cost of Service rate impacts.

A. Table 1 below summarizes the base rate impacts and the impacts with supplemental schedules included. Assumptions include a 10.50% ROE with a 50% equity capital structure, updated Net Variable Power Costs (NVPC), an updated load forecast, and the expected ratespread/rate design stipulation.

Table 1
Estimated Cost of Service Rate Impacts

	Estimated Rate Change (%) (base rates)	Estimated Rate Change (%) (with supplementals)
Schedule 7 Residential	5.5%	5.7%
Schedule 32 Small Nonresidential	4.0%	3.8%
Schedule 83 31-200 kW	6.4%	6.3%
Schedule 85 201-1,000 kW	1.4%	1.3%
Schedule 89 Over 1,000 kW	-1.8%	-1.6%
Street Lighting & Traffic Signals	0.1%	-0.6%
COS Overall	3.9%	3.9%

II. Status of New Tariffs and Corrections

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of our testimony is to provide an update to the new supplemental tariffs we proposed in our initial testimony, and to correct any language inconsistencies in our initial proposal. We also discuss proposed changes to Schedule 105, Regulatory Adjustments and Schedule 122, Renewable Resources Automatic Adjustment Clause.

Q. What is the current status of the new tariffs, Schedules 141 and 145 that you proposed in your initial testimony?

A. As part of the first revenue requirement stipulation, PGE has agreed to not pursue Schedule 141, Pension Adjustment Mechanism. PGE continues to advocate for the Schedule 145, Boardman Power Plant Operating Life Adjustment. Some parties to this case support the schedule, while only Kroger has offered testimony in opposition to this schedule.

Q. What are the corrections to your initial tariff proposals?

A. Generally, the corrections are mostly housekeeping in nature. We include language for Schedules 89, 585, and 589 that establish the minimum billing demand for primary voltage service at 200 kW, consistent with newly proposed Schedule 85. We also provide a minor typographical correction to Schedule 583. PGE Exhibit 2101 contains these corrections in redline format.

Q. Please describe the components of Schedule 105 and how you spread these components to the rate schedules.

A. The Independent Spent Fuel Storage Installation (ISFSI) tax credits of $17.8 million are spread on an equal percent of current revenues basis, with DA customers priced at COS. The SB 1149 Deferral residual amount is a credit of $1.5 million that is spread in the same manner as the ISFSI tax credit. Together, these two items comprise Part A of Schedule 105.

Part B consists of a credit of approximately $1.3 million for the 2010 Large Nonresidential Direct Access True-up, and a residual amount of approximately $0.5 million for the 2008 true-up. These amounts are spread to large nonresidential customers on an equal cents/kWh basis. Part C is the Schedule 127 residual credit amount of approximately $1.9 million. This UE 115 Power Cost Adjustment amount is spread on an equal cents basis to all customers. This treatment is consistent with its original spread. Part D of Schedule 105 recovers from customers the Intervener Funding payments made to Interveners pursuant to Commission orders. The costs are recovered from customer classes in accordance with the provisions of Order No. 03-388.

Q. How do you spread the deferral portion of the Schedule 122, Renewable Resources Automatic Adjustment Clause?

A. Consistent with the tariff provisions, we spread the deferral amounts related to Biglow II and Biglow III to each applicable schedule on the basis of generation revenue. The Biglow II amount is approximately $4.1 million and the Biglow III amount is estimated at $15.0 million.

III. City of Portland: Standard Schedules

Q. What is the purpose of this section of your testimony?

A. In this section of our testimony we rebut the City of Portland's recommendations regarding the structure and rate design of our standard rate schedules, in particular Schedules 32, 83, 85, and 89. We rebut their streetlighting proposals in the next section.

Q. Does the COP contest the marginal cost study or the proposed ratespread in this docket?

A. No, not explicitly, however the COP does propose that PGE reclassify service laterals and transformers as "facilities" rather than "customer" and that these costs be "avoidable." The COP primarily contests the rate design, therefore the prices charged to the individual nonresidential schedules after the revenue requirements have been spread to these schedules.

Q. What are the rate design (non-streetlighting) issues identified by the City of Portland (COP)?

A. Regarding rate design, the COP claims the following on page 4 of their testimony:

1. PGE's time-of-use (TOU) energy rates are either missing or inadequately justified.
2. Some of PGE's charges are "judgment calls".
3. Some of PGE's demand charges are flat or declining block, despite the fact that PGE will incur substantial future generation and transmission costs.
4. COP objects to PGE reclassifying service and transformers to the "customer" category from "facilities".
5. PGE's rate design does not take sufficient advantage of the new "smart meters."
6. The cumulative effects of PGE's rate design constitute a shift in costs from "avoidable" to "unavoidable" that "mutes price signals."

Q. What is the COP's remedy for these claimed issues?

A. The COP summarizes their proposals on page 30 of their testimony:

> 1. Reverse the proposed assignment of Service and Transformer costs to the Customer charge category.
> 2. Set the total tail-block Demand Charges at about $7.00-8.00/kW.
> 3. Add a time-of-use option to Schedule 83, modeled on Schedule 85.
> 4. Change the billing determinant for all demand charges in all rate schedules to the customer's peak load during the Peak period only.
> 5. Reduce inframarginal Facility Charges to achieve the revenue neutrality on an expected basis in each rate schedule.
> 6. Expand Schedule 123 to address the potential for underrecovery of fixed costs from volumetric charges due to these changes in rate design.
> 7. Provide specific information to customer's who are "in transition" from one rate schedule to another.
> 8. Add a seasonal shape to all energy charges.

Q. Does the COP explicitly propose a generation demand charge?

A. No. The COP does not explicitly propose a generation demand charge. Instead they have vague proposals such as tail-block Demand Charges "at about $7.00-8.00/ kW" coupled with negative first-block Distribution Facilities Capacity Charges for Schedule 89 that are not based on distribution costs. These proposals have the cumulative impact of inappropriately transferring the cost responsibility from smaller customers within a rate schedule to the larger customers within the same schedule.

Q. Does the COP provide any rate impact analysis for the different demand and load factor characteristics within the schedules for which they propose rate design changes?

A. No. The COP provides no such analysis that may enable the Commission or other parties to this docket to evaluate the specific effect their proposals may have on the various usage characteristics of commercial and industrial customers.

Q. Do you support any of the COP recommendations?

A. No, we oppose all of COP's recommendations. The COP creates supposed "problems", and then proceeds to design costly and unstable "solutions" to these "problems" that are counter to cost-of-service considerations. Generally, the COP, as part of its set of "solutions" seeks to impose a residential type of inclining block kWh rate design structure on the Demand and Facilities Capacity Charges of commercial and industrial rate schedules. The forthcoming joint stipulation testimony discusses the inappropriateness of this type of rate design as does the testimony that follows.

Q. How does the COP substantiate its first claim, that PGE's TOU energy rates are either missing or inadequately justified?

A. The COP states that the Schedule 32 TOU energy rates that are not "grounded in costs, either marginal or embedded." They further state that PGE has no TOU energy charges for Schedule 83, either mandatory or optional.

Q. Do you agree with the COP's criticisms?

A. No. The TOU option for Schedule 32 is the chosen "market-based rate option" included in the Portfolio Options mandated by Senate Bill 1149 and has been in place since 2002. The rate design for this optional schedule purposely exaggerates the on- and off-peak differentials in order to entice participation. The result of these exaggerated price differentials however, is that the average size Schedule 32 customer with a typical peak profile pays the same energy charges as a Schedule 32 customer who remains on the cost-based standard Schedule 32 pricing. Indeed, the mid-peak price is the same as the Schedule 32 standard tariff price. It is not only curious, but also inconsistent, as to why the COP would object to these large peak period differentials given their statements about wishing to shift load. The exaggerated peak period price differentials should be ideal for customers who wish to save on their monthly bill by shifting load.

With regard to Schedule 83, the COP's statement about TOU is not complete. PGE currently offers voluntary market-based monthly and daily price energy options that have separate on- and off-peak prices. PGE has had these options for nearly a decade.

In addition, as we pointed out to the COP in our Response to COP Data Request No. 28, PGE is interested in extending TOU pricing to more schedules at a future date. First PGE must ensure that its AMI system is fully operational and meter data collection and billing systems capabilities to implement TOU are thoroughly developed and tested over the next 12 to 18 months. The PGE Response to COP Data Request No. 28 is contained in PGE Exhibit 2102.

Q. Please specify what the COP means by "judgment calls" regarding some of PGE's proposed rates.

A. Certainly. On page 5 of their direct testimony, the COP takes issue with the composition of PGE's proposed customer charges across different rate schedules and the proposed Schedule 83 Facilities Capacity Charges. The COP states the following:

> In short, these Basic Charges are not clearly connected to cost recovery in any systematic fashion across rate schedules, and are in some cases significant departures from current charges.

Q. What is your policy regarding the proposed customer charges in this docket?

A. We consider the total bill impacts, with the customer charge as one component of the total bill. Basic Charges are more than a function of the percentage of customer-related costs. We do not blindly apply a fixed recovery percentage across schedules in some systematic manner as the COP seems to suggest we should. To do so could lead to poor rate design across the continuum of nonresidential rate schedules, with customers receiving large changes in their bills as they migrate from one rate schedule to another. Furthermore, as we explained to the COP in PGE Response to COP Data Request No. 009 (included in PGE

Exhibit 2102), we typically propose Basic Charges below marginal cost in order to mitigate large monthly bill increases for low-usage customers within schedules that have numerous customers. Schedules 7, 32, and to a lesser extent Schedule 83, are representative of schedules with a large number of customers.

The COP may consider such design considerations judgmental, but consideration of rate impacts across schedules is critical to an effective, stable pricing structure for all customers.

Q. Can you give some recent examples of how the Basic Charge can deviate from just a fixed percent application of marginal cost?

A. Yes. In this docket we stipulated to *reduce* the Schedule 7 Residential Basic Charge in order to mitigate the bill impacts to smaller consumption levels. This reduction in the Basic Charge was prompted by the stipulated change in the Schedule 7 blocking structure. Another example is the stipulation regarding the Schedule 85 Basic Charges for secondary and primary delivery voltages. In our direct testimony, we proposed Basic Charges that approximated cost, yet we stipulated to Basic Charges well below cost in order to alleviate other parties concerns about the rate impacts for the smaller, low load factor customers that will be on this schedule. The revenue shortfall in the stipulated Schedule 85 Basic Charges will be recovered through the Facilities Capacity Charges. We also note that this stipulation has the effect of subsidizing the smaller Schedule 85 customers at the expense of the larger Schedule 85 customers.

Q. Are you willing to price the Schedule 83 Facility Capacity Charge at the allocated marginal cost amounts in order to seem to be less "judgmental"?

A. Yes. However, we will continue to block this distribution charge in a declining block manner in order to better reflect distribution costs and to provide for a stable transition for

Schedule 32 customers that grow to exceed 30 kW, as well as the Schedule 83 customers whose demand falls below 30 kW.

Q. Does the marginal cost study indicate that a declining block structure is warranted?

A. Yes. Table 2 below, from the facilities portion of out marginal cost study points out the declining nature of distribution costs relative to customer size:

Table 2: Nonresidential Marginal Facilities Costs

Schedule	Feeder Local Facilities $/kW	Feeder Backbone $/kW
32 Three-phase	$9.16	$26.41
83 Three phase	$8.54	$22.89
85	$7.37	$20.32
89 1-4 MW	$4.74	$19.22

Based on the table above, it is clear that as customers increase in size, their unit distribution costs decrease. It is not surprising that these costs exhibit economies of scale. It is also clear that a rate design that both acknowledges this declining cost structure and provides for stable rate schedule migration in both directions is optimal.

Q. What is the basis of the COP criticism of your proposed demand charges?

A. On pages 5 and 6 of their testimony, the COP seems to assert that demand charges should be much higher and of an inclining block nature in order to provide better pricing signals. The COP cites the Schedule 7 Residential inclining block kWh charges as being the only schedule with an inclining block structure.

The COP also cites PGE's long-run marginal generation cost study and the generation capacity figure of $191.18/kW-year as the basis for an inclining block demand charge structure for applicable nonresidential schedules. The COP also attempts to link PGE's AMI investment as an additional reason to change PGE's rate design to include inclining block demand charges (COP/100, page 9, line 17 to page 10, line 2). The COP then claims that they are able to shift load from on-peak to off-peak at some of their pumping stations, yet the proposed Schedules 83, 85, and 89 do not allow them to reduce their energy costs by changing operations. Further COP assertions include erroneous statements regarding the "billing factors" of Schedules 85 and 89 and an incorrect statement that somehow Rule B does not allow for demand charges to be applied only during the on-peak hours.

Q. Do you agree with the COP regarding the need for higher demand and facilities capacity charges that are also inclining block in nature?

A. No. Our current Transmission Demand, Distribution Demand, and Distribution Facilities Capacity Charges are, as their name states, designed to recover transmission and distribution costs. They are designed to recover the allocated revenue requirement amounts to the respective schedules that have demand charges. The existence of the demand charges themselves is an effective price signal regarding a customer's peak demand. Furthermore, inclining block Distribution Demand or Distribution Facilities Capacity Charges are contrary to the declining cost characteristic we pointed out in Table 2 above. Finally, some of the COP's statements are incorrect regarding the application of demand charges. Rule B does not preclude time-differentiated demand charges. The COP is further mistaken when they state that the demand billing factors for Schedules 85 and 89 are the same as for Schedule 83. They are not. The Transmission and Distribution Demand Charges for Schedules 85 and 89 apply during the on-peak periods, as we specified in our direct testimony. Hence, contrary to the COP's assertions, Schedules 85 and 89 provide opportunities to shift load via the time differentiated energy charges and the on-peak Transmission and Distribution Demand Charges.

Q. Would higher demand charges necessitate lower volumetric (kWh) energy charges?

A. Yes. Even the COP acknowledges this on page 7 of their testimony. In addition, on page 7, the COP also acknowledges that this reduces the incentive to conserve energy or shift load.

The COP then crafts a "solution" to this, a problem that they have created themselves by stating a need for higher fixed costs. Their "solution" is the inclining block demand structure that has the consequence of inappropriately benefiting the existing smaller customers in a particular schedule at the expense of the large customers. To be clear, our concerns with the COP's proposal are not related to "small" or "large" customers per se, but rather that the COP proposals fundamentally deviate from pricing that is based on the cost to serve.

Q. Is there a simple solution to the COP's desire to incent energy efficiency?

A. Yes. Our proposed rate design with higher volumetric energy charges provides a strong incentive to encourage energy efficient behavior. The COP on the other hand, by advocating for higher fixed charges that reduce what they call "variable charges" creates a problem where one did not previously exist. They then "solve" this self-created problem by attempting to shift costs to larger customers within the nonresidential rate classes through an inclining block demand charge.

In addition to providing higher volumetric rates and therefore an incentive to conserve, our proposed rate design also avoids the negative aspects of the COP's poorly specified rate design—it does not discriminate against a customer simply because they are larger than another customer on the same rate schedule.

Q. What do you conclude regarding the COP's criticism of your demand charges?

A. We conclude that the COP's recommendations should be rejected. They are designed to shift cost responsibility to larger customers to the benefit of smaller customers. They furthermore are not grounded in cost-causation principles that recognize the declining cost characteristics of the distribution system, and are contrary to the encouragement of energy efficiency. We know of no study that indicates that higher fixed charges coupled with lower variable charges leads to increased energy efficiency.

Q. Please state why the COP's objection to your classification of service and transformers as "customer" is misguided.

A. Certainly. Services and transformers are of standardized size, and once installed are a fixed cost of providing service to a customer or a group of customers. They generally remain in place for their useful lives and are rarely resized for a particular customer or group of customers. Therefore, service and transformer costs are appropriately classified as customer-related costs. These customer costs are appropriately recovered in Basic Charges and should not be "avoidable."

Q. Do you agree with the COP's assertion that PGE's rate design does not take sufficient advantage of the new "smart meters."

A. Our objection to this COP statement is more a matter of timing rather than substance. The COP is demanding TOU pricing for January 1, 2011, yet PGE has not completed all of its systems development and testing to ensure a smooth transition from accurately receiving interval data to ensuring that this interval data is accurately processed into billing data. We informed the COP of this in PGE Response to COP Data Request No. 28, yet the COP still insists that PGE provide a pricing structure for which it is unable to guarantee effective implementation in 2011.

Q. Please provide your assessment of COP's sixth assertion, regarding your proposed rate design in general.

A. We strongly disagree with the COP. We have demonstrated above that the COP's assertions about "avoidable" costs versus "unavoidable" costs are unfounded, and contrary to basic economic and ratemaking principles of achieving cost-based rates. We appropriately functionalize and categorize costs and propose a rate design that recovers these appropriately categorized costs. Contrary to the COP's statements concerning energy efficiency, we propose volumetric energy charges that send a strong price signal for energy efficient behavior. These volumetric charges are time-differentiated for all customers above 200 kW. We have furthermore demonstrated that the COP's proposals are merely an unwarranted shift in cost responsibility from smaller customers to larger customers. The COP is not simply "muting" price signals, but completely distorting them.

Q. Does the COP specify how they would apply their proposals to the nonresidential rate schedules?

A. To some degree, yes. The COP has recommendations for Schedules 32, 83, and 89.

Q. What does the COP recommend for Schedule 32?

A. The COP recommends the following regarding the Schedule 32 TOU Portfolio Option:

> This TOU structure should be tied to the capacity and energy costs that PGE expects to incur, similar to what we have proposed regarding demand charges.

The COP also takes issue with the declining block nature of the Schedule 32 distribution charges, and the manner in which we deal with rate migration from one schedule to another.

Q. Do you agree with the COP?

A. No. Above, we explain that the COP presents contradictory criticisms of the Schedule 32 TOU rate design. Indeed, the large on- and off-peak differentials in the current Schedule 32 TOU option provides the COP exactly what they say the want—an incentive to shift load.

Regarding the distribution charge blocking, we point out that the 5,000 kWh monthly threshold is unusually large consumption for a Schedule 32 Small Nonresidential customer. In 2009, only about 7% of Schedule 32 monthly bills exceeded this threshold. In addition, this blocking allows for a stable transition between customers migrating from a volumetrically priced schedule to a schedule with demand charges and vice versa.

Q. What are the COP's criticisms of your Schedule 32 rate design with respect to rate migration?

A. The COP claims on page 21 of their testimony that the Schedule 32 rate design contains incorrect price signals that are motivated by easing the transition from Schedule 32 to Schedule 83. The COP implies that the Schedule 32 rate design has a poor policy objective: "making it easier for customers to move "up" in the rate structure."

Q. Do customers only migrate "up" as the COP states?

A. No, customers also migrate "down" rate schedules. Therefore it is imperative that good rate design consider these transitions in both directions. For example, in some cases, when the Facility Capacity of a Schedule 83 customer falls below 30 kW they are placed on Schedule 32. Possible reasons for the downward migration include installation of energy efficiency measures on the part of customers. As we pointed out above, very few of the bills for Schedule 32 are above the 5,000 kWh threshold. Thus, the COP's statement about "incorrect price signals" is misleading at best for the majority of Schedule 32 customers. In short, our rate design provides for rate stability to customers across the rate schedule continuum. Rate stability is, in our opinion, fundamental to ratemaking; it is also a desirable trait in rate design that is lacking in the COP's proposals. Ignoring this fundamental ratemaking principle can lead to customers experiencing dramatic changes in monthly bills when they migrate up or down the nonresidential rate schedule continuum.

Q. What is the COP's proposal regarding rate migration?

A. On page 21 of their testimony the COP proposes a complex set of automated notices and bill comparisons for customers who approach a "Demand Event." The implication is that it is preferable that customers remain on the "lower rate schedules." The COP also specifies that PGE will have to change its billing system to meet their proposal and that the sum of their Schedule 32 proposals will somehow encourage more efficient use of electricity.

Q. Do you agree with any of the COP's assertions above?

A. No. As we have explained above, rate migration, up or down is not a significant issue with PGE's carefully designed rates. Furthermore, we see no evidence that the COP's proposals encourage efficient use of electricity as they state. Once again, the COP creates a problem where one previously did not exist, and then proposes a complicated and costly "solution." The fact that the COP has to advocate warnings and alarms is evidence of the unstable rate design they propose. There is no reason to alarm a customer for approaching a particular demand threshold if an appropriate, stable rate design such as the one we propose is in place. In addition to being unnecessary, the COP's proposal would also be costly. Our billing and customer service departments have informed us that our current billing system cannot automatically generate the bill comparison and warning letters that the COP advocates. These bill comparisons and warning letters would need to be done manually and would require hiring additional personnel.

Q. What do you conclude about the COP's proposed treatment of rate migration?

A. We conclude that their proposal is indicative of the instability of the COP's nonresidential rate design recommendations. Their proposal is both unnecessary and costly, and should be rejected.

Q. What does the COP propose for Schedule 83?

A. The COP proposes TOU energy charges for Schedule 83 similar to what we propose for Schedule 85. In addition they propose that the Facility Capacity Charge apply only during the on-peak periods for Schedule 83 and other schedules that have Distribution Demand and Facility Capacity Charges.

Q. Do you agree with the COP's Schedule 83 recommendations?

A. No. We have already demonstrated that Schedule 83 currently has voluntary on-and off-peak energy charges. We have furthermore demonstrated that the COP may receive service from an ESS where they may specify alternative types of energy pricing structures. In addition, we already specified that PGE does not have the resources available to implement yet another energy pricing option at this time.

Q. Do you agree that the Facility Capacity Charge should apply only during on-peak periods?

A. No. As correctly pointed out by Staff, (Staff/1100, page 11, lines 13-15), the Facility Capacity Charge and the Basic Charge are designed to recover functionally related cost categories (i.e., the last segments of the distribution system including the customer interface). The distribution facilities that are recovered through the Facility Capacity Charge are largely facilities that are sized to meet the individual customer peak regardless of time period. In addition, the Facilities Capacity Charge is frequently used to recover customer-related costs that are not recovered through the Basic Charge. Our stipulation regarding treatment of the Schedule 85 Basic Charge is a good example of this. Therefore, it makes no economic sense to make this charge "avoidable" when it reflects to such a large extent specific customer-related costs.

Q. What does the COP specifically recommend for Schedule 89?

A. The COP states the following:

> **Q. WHAT DO YOU PROPOSE FOR SCHEDULE 89?**
>
> A. First, it is important that all customers see a greater incentive to shift or reduce peak loads, irrespective of size. Second, all three voltage levels of

> Schedule 89 have a very small tail-block Facility Charge. This means that the largest customers in Schedule 89 have the *lowest* incentive to reduce or shift peak loads, and the *greatest* incentive to increase peak loads. As these are likely to be the customers with the greatest knowledge and understanding of their energy costs, this seems to be a perverse result. In addition, these customers are all greater than one MW by definition. The solution is merging the second and third Facility Charge demand blocks. The charges for this tail-block would be set at $7-$8.00/kW, so that all customers on this revised Schedule 89 would face the same marginal demand charge, and the inframarginal charge adjusted downward accordingly to achieve revenue neutrality within the customer class. For Schedule 89-Primary and 89-Subtransmission, this approach may lead to *negative* Facility Charges for the first 1,000 kW. However, this means that the total expected bill for this customer class is the same, while creating a much stronger incentive to reduce or shift peak period loads.
>
> **Q. SHOULD PRICES ALWAYS BE POSITIVE?**
>
> A. No. Negative prices can be rational in a variety of situations. The most apt example may be "negative salvage value": the need to pay someone to take away an asset that has reached the end of its useful life. Instead of being paid for the asset, the owner must pay someone to remove it. Also, PGE's adjustment schedules contain many charges that can be positive or negative.

Q. Do you agree with the COP's proposed Schedule 89 rate design?

A. No. This "rate design" proposed by the COP is contrary to the Schedule 89 cost structure and inappropriately shifts cost responsibility from the smaller Schedule 89 customers to the larger Schedule 89 customers under the pretext of shifting or reducing peak load. We pointed out in our direct testimony that the tail-block Facility Capacity Charge is significantly lower for the customers who exceed 4 MW because their distribution facilities costs are significantly lower. Furthermore, the Facility Capacity Charges we propose are based on distribution costs—what the COP proposes is not distribution cost based, and results in implausible negative Distribution Facility Capacity Charges for customers that are not much over 1,000 kW in size. We strongly prefer a rate design that is cost-based rather than one that is not cost-based and inappropriately confers benefits to the smaller customers at the expense of the large ones within a rate schedule.

Q. Can you provide an example of the perverse types of incentives that the COP Schedule 89 rate design may provide?

A. Yes. New large customers would likely wish to take advantage of the negative Facilities Demand Charges that the COP proposes. Instead of consolidating their electrical needs, they could prefer to have smaller, multiple services so that they could have negative Distribution Facilities Capacity charges and avoid the artificially high tail-block charges. In short, PGE would incur higher costs that would eventually be passed on to other customers so that the new customer would incur lower electric bills. Existing Schedule 89 customers would have an incentive to deconsolidate their electrical service in some manner in order to be billed the negative Facilities Capacity charges and to avoid the artificially high tail-block charges. In both cases above, the customers do not change their consumption behavior. Instead, they react to the perverse rate design incentives that the COP proposes, resulting in an overall loss of efficiency. This makes no economic sense.

Q. Do you agree with the COP's assertion that negative Facility Capacity Charges are rational and are comparable to the negative salvage value of an asset?

A. Certainly not. Negative salvage is a cost, not a charge. This comparison makes no sense. It is true that many assets have a negative salvage value *at the end of their life*, but they provide positive value over their useful lives in order to serve the electrical needs of customers. Therefore a positive charge is the only rational charge for the Distribution Facility Capacity Charge.

Q. Are negative distribution Facility Capacity Charges comparable to the PGE supplemental schedules that may be negative or positive?

A. No. None of our supplemental schedules that may be both negative and positive are designed to recover distribution assets. The only current supplemental schedule that recovers the cost of distribution assets is Schedule 111 Advanced Metering Infrastructure; the charges for this schedule are positive.

Q. What do you conclude about the COP's proposed Schedule 89 rate design?

A. We conclude that the COP's proposed Schedule 89 rate design should be rejected. Once again, their proposed rate design is not based on costs, but is rather based on shifting cost responsibility from smaller customers to larger customers within Schedule 89. Their implausible negative Distribution Facility Capacity Charge proposal only highlights the degree to which the COP will go to achieve their desired shift in cost responsibility.

Q. Are there other proposals that the COP makes that are applicable to the nonresidential schedules?

A. Yes. On page 22, the COP states that PGE's nonresidential energy charges should be seasonally shaped in accordance with prospective 2011 Mid-Columbia prices.

Q. Do you agree that PGE should have mandatory seasonal energy charges for the 2011 test period?

A. No. We believe that this would not only be confusing to customers, but also that the large increase in prorated bills could increase call volume and the amount of phone time spent explaining bills. In addition, this COP proposal would affect the overnight batch processing of bills which could impact the system availability in the mornings for Customer Service Representatives. If the COP truly desires seasonal energy pricing they may obtain it from our market-based options or from an ESS.

Q. You have demonstrated that all of the COP's proposals should be rejected because they are: 1) frequently contrary to cost-based rates; 2) are costly to implement; and 3) are designed to shift cost responsibility from smaller customers to large customers. Is

there any other of the COP's eight non-streetlight proposals that you have not discussed?

A. Yes, we have yet to discuss the COP's proposed expansion of Schedule 123, Decoupling Adjustment to all customer classes.

Q. Are you in favor of the COP proposal to expand decoupling to all rate schedules?

A. No. Ordinarily, one would expect a utility to support full decoupling, but because the COP's rate design proposals are so contrary to cost-based ratemaking, we have no choice but to oppose their proposal if it means accepting any part of their "rate design."

Q. Please summarize why you urge the Commission to reject all of the COP's proposed changes to your proposed rate design.

A. Certainly. The COP's proposals are in many cases thinly disguised "rate design" changes that serve only to reduce the cost responsibilities of smaller customers at the expense of large customers within a particular rate schedule.

In addition, the COP proposes to have distribution costs such as services and transformers that are customer-related be "avoidable". These costs, if successfully "avoided" would then be passed on to other customers through the COP's global decoupling mechanism.

The COP unnecessarily seeks to impose seasonal energy charges on all nonresidential customers even though various voluntary energy pricing options already exist. This imposition of seasonal pricing is not only unnecessary, but potentially costly and confusing to customers.

The COP proposes changes in addressing rate migration that are both unnecessary and costly.

IV. Streetlighting

Q. What is the purpose of this portion of your testimony?

A. In this portion of our testimony we rebut the COP Schedule 91streetlighting proposals.

Q. What are the COP's Schedule 91 proposals?

A. The COP identifies three street lighting issues on page 31 of their testimony. They also mention a fourth, streetlight maintenance, so we include it here:

1. Adopt specific short-run solutions to the problem of limitations on lamp codes, while preparing for a long-term expansion of codes.
2. Credit the City of Portland so that the City pays for its "actual" share of streetlight circuits.
3. Reduce the proposed streetlight maintenance budget by $215,000, or eight percent. (COP/100 page 29, lines 4-5).
4. Consider eliminating the CIO.

Q. What does the COP's propose to remedy its concern with lamp codes?

A. The COP proposes the following three short-run solutions:

1. Use "unassigned" lamp codes for new lamps.
2. PGE should set up a process to "retire" lamp codes that become obsolete or are replaced.
3. Allow for "self-reporting" of Option C lamps, a system analogous to the self-reporting of intersections for Schedule 92 Traffic Signals.

Q. Does PGE have a limited number of available lamp codes?

A. Yes, PGE uses two numeric digits for lamp codes. PGE has only a few unassigned lamp codes available due to the increasing number of new lamps requested by Schedule 91 customers, primarily the COP.

Q. Has PGE recently addressed some of the requested new lamp types?

A. Yes. PGE Advice No. 10-11 filed June 7 is a housekeeping filing that incorporates the new lamp codes requested by the COP.

Q. Do you agree with the COP's first lamp code remedy?

A. Yes. PGE currently uses unassigned lamp codes for new lamps; however, Schedule 91 allows customers to experiment with new customer-owned, customer-maintained lamps. PGE bills the customers using a lamp code with similar kWh usage and costs. If the lamp type will be used on a permanent basis, PGE will incorporate the lamp into Schedule 91 using an unassigned lamp code.

Q. Do you agree with the COP's second lamp code remedy?

A. Not entirely. A lamp code can become obsolete for various reasons, however, the lamp codes for these obsolete lamp types are still necessary to bill customers that continue to use these obsolete lamps over their remaining life. The remedy proposed by the COP works only if the obsolete lamps are no longer in service.

Q. Do you agree with the COP's third proposal, to allow self-reporting for Option C luminaires, similar to what currently occurs for Schedule 92?

A. No. We believe that this proposal is appealing conceptually, but, unfortunately, would not be practical. Our Schedule 92 has only a handful of customers with 17 accounts that are self-reporting their traffic signal intersections and energy consumption. PGE currently finds it challenging to monitor the completed work requests for installs and removals for these small numbers of customers. In addition, PGE had to close this schedule to new service because some customers did not meet their self-reporting obligations. Unfortunately, not all municipalities are as responsible as the COP in self-reporting.

Self-reporting for Schedule 91 would present even more problems than we have encountered for Schedule 92. Currently PGE has 56 customers with Option C luminaires. Each of these 56 customers would require a designated person that could manage an inventory system allowing them to pull data on a monthly basis and provide a report to the appropriate PGE personnel. The PGE personnel that receive the reports would not only need to monitor the removals and installs for a large number of customers, but they would also have to ensure that all of the 56 customers would be reporting their services in the correct taxing district. To summarize, the COP idea has conceptual appeal, but is not practical.

Q. What is your opinion of the COP's long-term proposal, that PGE should move to either a three digit or alphanumeric lamp code?

A. We agree that more lamp codes are necessary to provide for additional technologies such as LEDs. PGE is currently working to expand the number of available codes. We anticipate that new codes will be available before running out of assigned codes.

Q. Regarding streetlight circuits, does the COP dispute the amount of the embedded costs for Schedule 91 streetlight circuits?

A. No. The COP asserts that it should pay less for streetlight circuits than other municipalities.

Q. Why does the COP assert that it should pay less for streetlight circuits than other municipalities?

A. The COP bases this assertion on the following criteria:

1. The COP states that they pay approximately 32% of the circuit charges, yet they have substantially less than 32% of both the number of total streetlight circuits, and the total streetlight circuit mileage.

2. The COP states that streetlight circuits are "at the end of the line" and not shared facilities requiring a cost allocator.

Q. Do you agree with the COP's assertions above?

A. Yes. We agree that the COP pays a substantial portion of the circuit charge costs. We also agree these costs should be allocated to lighting schedules.

Q. How does the COP propose that PGE implement this change in streetlight circuit cost responsibility?

A. The COP proposes that PGE continue to bill Schedule 91 customers for circuits similar to how it currently does, but then credit back to the COP its "share of circuits". This credit to the COP would then be "recovered by PGE from other Schedule 91 customers in whatever manner PGE and the Commission determine to be reasonable." (COP/100, page 26, lines 20-21).

Q. Do you agree with the COP that they should pay less than other municipalities for the embedded costs of streetlight circuits?

A. No. The COP has presented information based on a PGE response to one of their data requests that they have on average less circuits and less circuit miles per luminaire than the average municipality. However, they have not demonstrated that other municipalities have received a disproportionate amount of streetlight circuits for which they did not pay relative to the COP.

Q. Please explain.

A. Our current Schedule 300 provides a Schedule 91 line extension allowance (LEA) of \$0.0524/kWh. Because of the small amount of consumption associated with a streetlight, Schedule 91 customers typically exceed this line extension allowance and are required to pay for a portion of items such as streetlight circuits. We explained the concept of how the line extension allowance is applied to the COP in PGE Response to COP Data Request No. 15, attached as part of PGE Exhibit 2102.

In short, if the number of streetlight circuits differs from one municipality to another, it only suggests that the municipalities differ in how much they pay in advance for obtaining electrical service to their streetlights. It is not a basis to differentiate the charges for the embedded costs of streetlight circuits.

Q. Has the LEA always been this low?

A. No. Prior to February 2003, the LEA for streetlighting was almost twice the current amount, \$0.102/kWh. Therefore, it is feasible that streetlight customers who grew more rapidly prior to 2003 have contributed more to the embedded revenue requirement of streetlight circuits. Because of this, it is also possible that it is the COP that is being effectively subsidized rather than the other streetlighting customers.

Q. Are there other concerns you have regarding the form of geographical pricing that COP is proposing?

A. Yes. As a matter of policy, PGE does not geographically differentiate its prices for any of its rate schedules. Nothing that the COP presents in its testimony convinces us to deviate from this postage stamp pricing policy. We point out that we do not differentiate the Schedule 300 line extension allowance amount by geographical location; therefore it makes no sense to us to charge certain municipalities or government agencies different amounts.

Furthermore, should we price the COP streetlights differently from other municipalities, the other municipalities will no doubt wish for their own special form of pricing based on some form of differentiation from other municipalities. We feel that this type of geographical pricing based on single issue differences is bad public policy that will ultimately lead to numerous streetlight tariffs for specific municipalities.

Q. What do you recommend regarding the COP's assertions that they should pay less for streetlight circuits than other municipalities?

A. We recommend that the Commission reject the COP's proposal. The COP's assertion that it is paying for facilities outside the city of Portland is not supported and the imposition of location-specific pricing is not warranted.

Q. What is the basis of the COP's assertion that PGE should reduce its 2011 test period projected Schedule 91 maintenance amount by $215,000 or eight percent?

A. The COP asserts that certain Schedule 91 provisions may make PGE determine that luminaires are non-repairable instead of repairable, and hence shift a cost burden to the customer. Because of these Schedule 91 provisions, at COP/100 page 28, lines 5-11, the COP states the following:

> We are concerned that PGE may "lean" toward making decisions that shift costs to the customer in emergency situations, thus shifting the entire risk of replacement in an "emergency" to customers from PGE. We do not advocate giving the customer the right to challenge PGE's decisions in emergency situations. However, in compensation for taking on the risk of replacement instead of repair, customers should receive the benefit of the least-cost assumption for the dispatch of crews for emergency service.

Q. What is the least cost assumption referenced above in the COP's statement?

A. The COP is referring to a portion of PGE's marginal cost of streetlight maintenance model in which three types of crews are dispatched for emergency repairs. The COP's argument is predicated upon the result that would occur if only the least expensive type of repair crew was assumed to perform all emergency repairs. The COP also asserts that because in their opinion, the marginal cost of streetlight repair is overstated, the 2011 projection for streetlight maintenance must be overstated by this same amount ($215,000).

Q. Before demonstrating the fallacies of the COP's arguments can you please compare the projected 2011 amount of street and area light maintenance relative to historical amounts?

A. Yes, the tables below demonstrate the actual incurred street and area light maintenance amounts for the years 2005-2009 and the projected 2011 test period amount of maintenance. The first table shows only the nominal amounts, while the second table shows the maintenance amounts expressed in 2011 dollars, adjusted for inflation using a modest 2% inflation assumption. To facilitate comparison, we present not only the dollar amounts, but also the amounts per light.

Table 3: Nominal Maintenance per Light: 2005-2009 compared to 2011

Year	Maintenance	Area, STL A&B Lights	Unit Cost
2005	$2,497,167	142,550	$17.52
2006	$2,481,847	145,666	$17.04
2007	$2,400,668	148,444	$16.17
2008	$2,818,902	152,391	$18.50
2009	$3,000,785	153,239	$19.58
Average			$17.78
2011	$2,668,147	160,440	$16.63

Table 4: Real Maintenance per Light: 2005-2009 compared to 2011

Year	Real Maintenance	Area, STL A&B Lights	Unit Cost
2005	$2,812,216	142,550	$19.73
2006	$2,740,160	145,666	$18.81
2007	$2,598,560	148,444	$17.51
2008	$2,991,441	152,391	$19.63
2009	$3,122,017	153,239	$20.37
Average			$19.22
2011	$2,668,147	160,440	$16.63

Q. What do the tables above demonstrate?

A. The tables demonstrate that even before adjusting for inflation, the projected 2011 level of lighting maintenance is well below the average amount of maintenance per light incurred over the most recent five-year period. With a modest 2% inflation assumption, the projected 2011 level of lighting maintenance is more than 13% below recently incurred levels. This strongly suggests that the amount of 2011 projected street and area light maintenance is likely understated rather than overstated as the COP asserts.

Q. Does the amount of 2011 test period maintenance result in an increase or a decrease in maintenance rates for applicable street and area light customers?

A. The result is a decrease in maintenance rates for the applicable lighting customers.

Q. Returning to the COP's assertions, for what purpose do you use the marginal cost of streetlight maintenance model?

A. We use this to allocate the projected test period maintenance amounts to the various lamp types.

Q. Do you use this model to determine the projected test period maintenance amount?

A. No. If we had used the model for this purpose, the amount of projected maintenance would have been greater than $3.0 million. Even using the COP's unjustified adjustment, the amount would have been over $2.8 million. The amount we propose in this docket is less than the amounts above.

Q. How was the projected 2011 maintenance amount determined?

A. The 2011 projected maintenance amount was determined by evaluating the first nine months of actual 2009 maintenance combined with the last three months of projected maintenance. This 2009 figure of $2.64 million was then used as the basis for the 2011 amount of $2.67 million.

Q. What do you conclude about the COP's proposed street and area light maintenance adjustment?

A. We conclude that the COP's proposed adjustment should be rejected because it is based on erroneous assumptions and the amount of proposed 2011 test period maintenance is well below historical incurred amounts.

Q. What does the COP recommend regarding the CIO?

A. The COP recommends that the Commission consider eliminating the CIO in this docket. They claim that the CIO interferes with "broader policy goals" previously articulated by the Commission in the UE 180 docket.

Q. Did the COP oppose Schedule 91 receiving a CIO credit in UE 180?

A. No. Schedule 91 received a CIO credit of approximately $583,000 in UE 180, to which the COP did not object.

Q. Does the ratespread/rate design stipulation you have reached with other parties reduce the amount of the CIO subsidy?

A. Yes. The stipulation reduces the CIO subsidy from nearly $14 million to approximately $7.8 million. Our most recent estimate is that Schedule 91 would contribute approximately $122,000 to the CIO.

Q. What do you conclude regarding the COP's CIO proposal?

A. We conclude that it should be rejected and we recommend that the Commission approve the CIO to which the other parties in this case have agreed.

V. International Dark Sky

Q. What does the International Dark Sky Association (IDA) propose?

A. The IDA proposes that PGE be required to offer two new Schedule 91 options:

1. A Midnight Optional Rate
2. 50 watt High Pressure Sodium (HPS) lamps should be added wherever 100 watt HPS lamps are offered.

Q. Have Schedule 91 customers been requesting these options from PGE?

A. PGE has had little or no customer interest in the Midnight Optional Rate. In addition, PGE's customers have expressed only limited interest in 50 watt high pressure sodium lamps. PGE routinely converses with Schedule 91 customers, so the opportunity to address emerging lighting needs is always available.

Q. What do you conclude about being required to offer options for which customers have little or no demand?

A. We do not believe that PGE should be required to provide options for which there is little or no evidence of demand from our customers. We recommend that the Commission reject IDA's proposals.

VI. Decoupling

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of our testimony is to rebut the decoupling proposals of OPUC Staff and CUB.

Q. What does CUB propose for the Schedule 123 Decoupling Adjustment?

A. CUB proposes that decoupling continue for an additional three years beyond the two-year period the Commission specified in Order 09-020. CUB also proposes that PGE have an independent consultant review the decoupling mechanism after it has been in place for five years. Finally, CUB recommends that the volumetric fixed charge rates be calculated as the difference between the total volumetric tariff rates for both Schedules 7 and 32 and the projected short-term marginal cost of power, a projection of Mid-Columbia prices. We presume that this projection of 2011 Mid-Columbia prices would coincide with the 2011 projections used in our final UE 215 power cost update and remain in place until PGE's next general rate case.

Q. What concern does CUB raise regarding the change in the fixed cost recovery rate from UE 197?

A. CUB expresses concern about the level of the fixed cost recovery rate relative to the fixed cost recovery rate currently in place. CUB asks PGE to explain this approximate 25% increase in fixed cost recovery attributable to Schedule 7, Residential Service.

Q. Do you have an Exhibit that addresses CUB's concern about fixed cost recovery rates?

A. Yes. PGE Exhibit 2103 demonstrates that the level of increase in fixed cost recovery attributed to Schedule 7 is in line with the amount of fixed cost recovery overall.

Specifically, this exhibit shows that the Schedule 7 generation fixed costs are higher than the overall increase in fixed generation cost relative to UE 197. This increase in fixed generation attribution is offset by relatively lower transmission and distribution cost attribution to Schedule 7.

Q. What does Staff propose for decoupling?

A. Because Staff is concerned that PGE does not incur fixed costs for generation and transmission on a per customer basis, Staff proposes a bifurcation of the Schedules 7 and 32 Sales Normalization Adjustment (SNA). Staff has a specific concern that a situation may arise where a decline in usage per customer from that projected, in combination with a growth in the number of customers from that projected, would interact in such a manner that the total kWh consumption would exceed the projected total kWh consumption for Schedules 7 and/or 32. With respect to transmission and fixed generation, Staff's proposal effectively fixes the 2011 energy consumption for Schedules 7 and 32 beyond the test period at 2011 projected levels, presumably until PGE files another general rate case. For costs other than transmission and generation, the SNA would operate as it currently does, with the updated comparative values resulting from this docket.

Q. Please evaluate the Staff concern.

A. We believe that the Staff concern describes a situation unlikely to occur, or certainly no more likely to occur than the converse situation where a decrease in customer growth occurs, yet PGE refunds because of increased use per customer. Indeed, this is precisely what occurred in the first year of decoupling. By limiting total consumption beyond the test-period for transmission and generation values, Staff is minimizing the opportunity for

PGE to offset inflationary increases in O&M through margin contributions. The likely result is more general rate filings.

Q. Given the two decoupling viewpoints above, what do you recommend to the Commission?

A. We recommend adoption of CUB's proposal for an independent evaluation. However, we recommend that the evaluation occur after the fourth year of the decoupling mechanism instead of after the fifth year as CUB proposes. In this manner, the independent consultant can make specific recommendations to the Commission regarding PGE's decoupling mechanism before the conclusion of the fifth year. We also propose that the Commission not change the fixed cost recovery rate methodology currently in effect and previously approved in OPUC Order 09-020. The purpose of the decoupling mechanism is to help remove disincentives to energy efficiency by allowing for recovery of fixed costs revenue requirements; it is not to perfect a particular rate. PGE and affected parties only have one year of experience with this approved mechanism. We believe that the approved mechanism should be the basis of the independent evaluation. We do however, propose that this independent evaluation not only address the six questions posed by the Commission in the order referenced above, but also that the independent evaluation address the issues identified by CUB and Staff regarding the appropriate fixed cost recovery rates and whether the SNA should be bifurcated as proposed by Staff.

Q. Does this conclude your testimony?

A. Yes it does.

List of Exhibits

PGE Exhibit	Description
2101	Tariff Corrections
2102	PGE Responses to COP Data Requests
2103	Schedule 7 Fixed Cost Recovery Rates: UE 215 versus UE 197

SCHEDULE 89 (Continued)

ELECTION WINDOWS

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.

November Election Window

Enrollment for the November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Enrollment Windows will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission 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 service facilities. The minimum Facility Capacity and Demand (in kW) will be ~~100~~ 200 kW and 4,000 kW for primary voltage and Subtransmission voltage service respectively.

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 585 (Continued)

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.

FACILITY CAPACITY

The Facility Capacity shall 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.

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 200 kW for primary voltage service.

REACTIVE DEMAND CHARGE

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.

NOVEMBER ELECTION WINDOW

Enrollment for the November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Enrollment Windows will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(31 – 200 kW) **(C)**

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has not exceeded 200 kW more than once in the ~~proceeding~~ preceding 13 months and who have chosen to receive Electricity from an Electricity Service Supplier (ESS). **(C)**

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)*:

(D)

Basic Charge		
Single Phase Service	$20.00	**(I)**
Three Phase Service	$30.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$3.00	**(I)**
Over 30 kW	$2.50	**(I)**
per kW of monthly Demand	$1.83	**(R)**
System Usage Charge		
per kWh	0.380 ¢	**(I)**

(D)

* 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 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (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.

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.

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~~ 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

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.

NOVEMBER ELECTION WINDOW

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During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

May 04, 2010

TO: Benjamin Walters
Office of City Attorney

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to City of Portland Data Request
Dated April 22, 2010
Question No. 009

Request:

Please explain the proposals to set the Schedule 85 Basic Charges at full marginal customer-related costs, the Schedule 89 Basic Charges at 90% of marginal customer-related costs, and the Basic Charges for Schedules 7, 32 and 83 at "considerably below" marginal customer-related costs.

Response:

PGE proposes to set the monthly Schedule 85 Basic Charges at marginal cost in order to better match monthly charges with the nature of the costs incurred by PGE to serve these customers. PGE proposes to set monthly Schedule 89 Basic Charges at 90% as opposed to 100% of marginal cost in order to partially mitigate the large absolute value increase in these proposed charges.

PGE typically proposes Basic Charges below marginal cost in order to mitigate large monthly bill increases for low-usage customers within schedules that have numerous customers. Schedules 7, 32, and to a lesser extent Schedule 83, are representative of schedules with a large number of customers.

May 05, 2010

TO: Benjamin Walters
Office of City Attorney

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to City of Portland Data Request
Dated April 22, 2010
Question No. 015

Request:

Please describe in detail the difference between line extension costs charged for traffic signals and street lighting, as identified in Rule I and Schedule 300, and street lighting circuit charges, as provided in Schedule 91.

a. Please describe in detail how line extension costs for traffic signals and street lighting are calculated, including the formula elements and the various cost elements.

b. Please separately describe what elements of the line extension costs are charged to the FERC account for circuit charges and provide supporting documentation.

c. Please describe in detail how line extension costs and street lighting circuit charges do not constitute duplicate cost recovery, including an identification of the cost elements contained in both that are different and that are the same or similar.

d. Please describe in detail how PGE accounts for cost recovery for line extension costs and street lighting circuit charges to avoid overlapping cost recovery for these charges.

e. Please describe in detail how Line Extension Cost Allowances have been recovered since January 1,2005, including an identification of the FERC accounting for such Allowances, the rate schedules to which such

Allowances are allocated, and the amounts recovered in rates for each schedule for each year.

f. Please provide documentation for any Line Extension Costs actually charged to the City of Portland since January 1, 2005.

Response:

a. Line extension costs include labor and materials as described in PGE's Schedule 300 and Rule I. The cost to the customer is the line extension cost minus the applicable line extension allowance.

b. All line extension costs are recorded to FERC Account 101, Plant In-Service. As noted under the response to question a, such costs include labor and materials as described in PGE's Schedule 300 and Rule I. Estimated costs that exceed the line extension allowance are billed directly to the customer, and are recorded as an offset in FERC Account 101, Plant In-Service. FERC subaccount 373-1 represents the streetlighting circuit including: conductors, insulator, splices, etc. The investment in FERC account 373-1 forms the basis for the circuit charge in Schedule 91. Other line extension amounts are recorded in FERC distribution subaccounts in FERC Account 101, Plant In-Service. These are spread to various rate schedules as part of rate base for rate setting purposes.

c. and d. Costs incurred up-to the line extension allowance amount are recovered through rate base. Costs exceeding the line extension allowance are directly recovered from the customer, under which the net effect to rate base is zero. As such, no costs constitute duplicate cost recovery.

To illustrate, a certain line extension allowance is $500. The cost of the line extension is $600. The $500 is recovered through rate base under utility plant in-service. The additional $100 is billed to the customer. Thus a $100 charge with a corresponding $100 reimbursement paid by the customer, resulting in a net zero impact to rate base.

e. See the response to subparts b. c. and d. above relating to line extension cost allowances. As noted in such responses, line extension allowances are included in rate base as part of Plant In-Service. Generally, line extension allowances are recorded in FERC distribution accounts. Rates are not generally set in a way that would enable PGE to track revenues from such rate base component.

f. Confidential Attachment 015-A contains the requested available information.

UE 215
Attachment 015-A

Confidential and Subject to Protective Order No. 10-056

Provided Electronically Only

Line Extension Costs

May 24, 2010

TO: Benjamin Walters
Office of City Attorney

FROM: Randy Dahlgren
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UE 215
PGE Response to City of Portland Data Request
Dated May 10, 2010
Question No. 028

Request:

Regarding PGE's response to COP-012: (a) Please identify PGE's currently expected "later date" for offering time-of-use pricing to Schedule 83 customers, and describe the assumptions, rationales and the justification for such estimated date; and (b) Please provide an estimate of the total personnel time (PGE and/or contractor) required to implement time-of-use pricing for Schedule 83 customers.

Response:

a) PGE has not identified a specific date for implementing time-of-use (TOU) pricing for Schedule 83 customers. PGE does not propose to add TOU pricing until the AMI system is fully operational and meter data collection and billing systems capabilities to implement TOU are thoroughly developed and tested over the next 12 to 18 months.

b) PGE has not performed the requested study assuming AMI systems are utilized. Costs to implement TOU for Schedule 83 on without the use of AMI-enabled interval data are expected to require temporary meter installations and thus are very costly.

PGE estimates that it would cost approximately $2.4 million dollars to install and program temporary meters to enable TOU pricing for the 11,000 Schedule 83 customers by January 1, 2011. In addition, Customer Information Systems (billing) and meter data systems would require significant manhours beyond AMI planned development to enable the TOU pricing for Schedule 83 customers.

PORTLAND GENERAL ELECTRIC
Schedule 7 SNA
Fixed Cost Recovery Comparison

Schedule 7 SNA

Schedule 7 Tariff Category	UE 215 Price mills/kWh	UE 197 Price mills/kWh	Percent Change
Transmission & Ancillary	2.43	2.12	14.6%
Distribution	30.14	26.14	15.3%
Trojan Decommissioning	0.18	0.23	-21.7%
CIO	0.00	0.10	-100.0%
Fixed Generation	25.67	17.87	43.6%
Totals	58.42	46.46	25.7%

Revenue Requirements

Revenue Requirement Category	UE 215	UE 197	Percent Change
Transmission & Ancillary	$41,838	$34,774	20.3%
Distribution	$422,967	$355,870	18.9%
Trojan Decommissioning	$3,498	$4,642	-24.7%
Fixed Generation	$442,145	$327,373	35.1%
Totals	$910,448	$722,660	26.0%