Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

August 9, 2010

Via Electronic Filing and U.S. Mail

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

Re: UE 215

Attention Filing Center:

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

- **JOINT TESTIMONY & EXHIBITS IN SUPPORT OF THE STIPULATION REGARDING REMAINING ISSUES FILED AUGUST 2, 2010**

This 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:smc
Enclosures
cc: UE 215 Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 215

Request for a General Rate Revision

PORTLAND GENERAL ELECTRIC COMPANY

Stipulation Regarding Remaining Issues
Joint Testimony & Exhibits

August 9, 2010

Table of Contents

I. Introduction

Q. Please state your names and positions.

A. My name is Judy A. Johnson. I am a Program Manager of the Revenue Requirements Section in the Electric and Natural Gas Division at the Public Utility Commission of Oregon (OPUC). My qualifications appear in Staff Exhibit 101.

My name is Bob Jenks. I am the Executive Director of the Citizens' Utility Board of Oregon (CUB). My qualifications appear in CUB Exhibit 101.

My name is Jay Tinker. I am a Project Manager for Portland General Electric (PGE). My qualifications appear in PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. Our purpose is to describe the stipulation reached regarding the cost of capital, PGE's Power Cost Adjustment mechanism (PCAM), and miscellaneous other items by the OPUC Staff (Staff), CUB, Industrial Customers of Northwest Utilities (ICNU), Fred Meyer Stores and Quality Food Centers (Kroger), and PGE (collectively, the Stipulating Parties). With the exception of PGE's proposed Boardman tariff, which has been stipulated to by a subset of these Stipulating Parties (CUB, Staff, and PGE), this stipulation resolves all remaining issues among the Stipulating Parties in this proceeding.

Q. What is the basis for this Stipulation?

A. Prior settlement discussions in this case led to stipulations resolving most revenue requirement issues and narrowed the remaining issues in the case considerably. On July 1, 2010, the Stipulating Parties filed the first Stipulation and Joint Testimony related to Revenue Requirement issues. On July 22, the Stipulating Parties met again in an attempt to resolve the remaining issues in this case.

On July 29, 2010, the Stipulating Parties filed a Stipulation and Joint Testimony related to Power Cost issues and on August 2, 2010, the Stipulating Parties filed two additional Stipulations and Joint Testimony related to other revenue requirement issues and to rate spread and rate design issues. The settlement discussions held on July 22, resulted in a stipulation on the remaining issues (again, with the exception of the Boardman tariff for ICNU and Kroger), which is provided as Exhibit 501.

Q. Please summarize the cost of capital and PCAM stipulation.

A. The Stipulating Parties agree that:

- PGE's Return on Equity (ROE) should be set at 10.0%.
- PGE's capital structure should be established at 50% equity and 50% long-term debt.
- PGE's cost of long-term debt is 6.065%.
- PGE's overall cost of capital is 8.033%.
- The above values determining PGE's overall cost of capital are reasonable.
- PGE's PCAM should be modified to incorporate a deadband extending from $30 million for positive power cost variances to a negative $15 million for negative power cost variances. This modification is for the current case, with the expectation that the size of the deadband can be revisited in future general rate cases.
- PGE's Schedule 123 decoupling mechanisms should be extended through December 31, 2013. The Stipulating Parties also agree that PGE will engage the services of an outside consultant to evaluate the decoupling mechanisms, with the evaluation to include, at a minimum, responses to the questions in Exhibit "A" of the Stipulation included in Exhibit 501. PGE will pay the first $50,000 of the costs

of the consultant's analysis. This $50,000 will not be recovered from ratepayers, but is an expense that will be borne by the Company.

- PGE should transfer the 2011 revenue requirement of PGE's Sunway 3 investment from the 2011 Renewables Adjustment Clause (RAC) proceeding in OPUC Docket UE 220 to this rate case. The result is an increase in the 2011 test year revenue requirement in this proceeding of approximately $256,000. However, there will be a corresponding decrease in PGE's Schedule 122 revenue requirement for 2011.
- PGE should reduce rate base to create a $100,000 revenue requirement decrease as a compromise of issues related to the Clackamas Hydro relicensing.
- PGE should increase Other Revenue to create a $1 million revenue requirement reduction for purposes of reaching overall settlement among the parties.
- PGE agrees to withdraw its application for deferred accounting related to 2010 pension costs in OPUC Docket UM 1462.

Q. With this stipulation, can a final non-power cost revenue requirement be determined?

A. Yes. This stipulation, combined with the prior stipulations, results in a 2011 PGE non-power cost revenue requirement of $1.006 billion, as demonstrated in Exhibit 502. We note that Commission determination of the remaining unresolved issues in the case (Boardman tariff for ICNU/Kroger, and IDA/City of Portland rate spread and design issues) will not impact this result. At this revenue requirement, the non-power cost revenue increase is $100.2 million, or approximately 5.9%. PGE's initial filing sought an increase in non-power cost revenues of $157.8 million, or approximately 9.4%.

PGE's power cost forecast filed July 30, which includes the impacts of the Power Cost Stipulation filed on July 29, 2010, results in a decrease in power cost revenues of approximately $49.9 million, or approximately a 2.9% decrease. Thus, the current estimated overall impact of this general rate case proceeding is an increase in annual revenue requirement of approximately $50.3 million ($100.2 million less 49.9 million), or approximately 3.0%, also demonstrated in Exhibit 502.

The overall increase resulting from the multiple stipulations is, however, subject to change pursuant to a final load forecast update, which PGE will file in September, as well as a final power cost update, scheduled in mid-November.

II. Resolved Issues

Q. Please describe the stipulation regarding PGE's required Return on Equity (ROE).

A. The Stipulating Parties agree that a 10.0% ROE is reasonable for PGE's 2011 test year.

Q. What is the basis for the stipulation regarding ROE?

A. In filed testimony (Staff/900), Staff supported an ROE of 9.2%, after adjusting for decoupling. ICNU-CUB (ICNU-CUB/200) supported a figure of 9.7%. PGE's proposed ROE was 10.5% (PGE/1200). The stipulated ROE maintains the figure at its current authorized level. The stipulation represents a compromise of the various positions of the Stipulating Parties.

Q. Please describe the stipulation regarding PGE cost of long-term debt.

A. The Stipulating Parties agree that the cost of long-term debt should be 6.065%.

Q. Please describe the stipulation regarding PGE capital structure.

A. The Stipulating Parties agree that a capital structure of 50% equity and 50% long-term debt is reasonable.

Q. What is the overall cost of capital given the agreed-to terms above?

A. The overall rate of return, resulting from the above values agreed to by the Parties, is 8.033%.

Q. What is the basis for the stipulation regarding PGE's capital structure?

A. In its filed testimony (ICNU-CUB/200), ICNU-CUB supports a 47.8% equity component of capital structure while PGE (PGE/1100) and Staff (Staff/900) support a 50/50 capital structure. ICNU-CUB's primary argument in support of a lesser equity component was an analysis of PGE's recent actual capital structure, which has been somewhat below the 50% equity level. However, for purposes of this case, the Stipulating Parties agree that PGE's target capital structure is appropriate.

Q. Please describe the stipulation regarding PGE's PCAM.

A. The Stipulating Parties agree that deadbands applicable to PGE's PCAM should be modified to fixed amounts of $30 million when power costs are higher than the base level established in rates, and $15 million when power costs are lower than the base level established in rates. Other elements of the PCAM, including the earnings test, remain unchanged. This change is for this case only. Parties are free to advocate different deadbands in future general rate cases.

Q. How are the deadbands determined under the current PCAM structure?

A. Under the current structure, the deadbands are a function of ROE, with the upper band defined as 150 basis points of authorized ROE and the lower deadband defined as 75 basis points of authorized ROE. As a result, the current mechanism results in larger deadbands in dollar terms as PGE's rate base grows.

Q. What is the basis for the stipulation regarding PGE's PCAM?

A. In their filed testimony (ICNU/100, Staff/500, CUB/100), various parties argued that the current PCAM structure is reasonable. The parties contend that a substantial reduction in the deadbands would constitute an unreasonable shift of risk to customers and that the PCAM was operating consistent with its intended purpose and with principles identified by the Commission in Order 07-015. In opening and rebuttal testimony, PGE supported symmetrical deadbands and narrowing the deadbands to positive and negative $10 million, along with changes to the earnings test. PGE argued that the current PCAM structure is outside of the mainstream recovery mechanisms operable for most utilities, including those with which PGE competes for capital.

The proposed agreement represents a compromise of positions, and the Stipulating Parties believe the modification to the PCAM is reasonable. The Stipulating Parties note that the agreed upon fixed $30 million and $15 million deadbands are approximately the same size as the deadbands that actually applied to PGE's power costs for 2009 (as filed in UE 221) which are $29.4 million and $14.7 million respectively. Further, the modified deadbands are still consistent with the principles identified with the Commission in Order 07-015. Those principles 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. Do the Stipulating Parties believe the PCAM modification is reasonable in light of the agreed-upon cost of capital?

A. Yes. The Stipulating Parties believe that the risk-mitigating attributes of the PCAM, as modified by this agreement, are consistent with the cost of capital values proposed in this Stipulation.

Q. Do the provisions of the stipulation address any other issues regarding PGE's tariffs?

A. Yes. The Stipulating Parties agree that PGE's Schedule 123 SNA decoupling and LRR revenue recovery mechanisms should be extended for a 3-year period ending December 31, 2013. To facilitate an in-depth review of the operation of the mechanisms and to address issues raised by CUB and by OPUC Staff, the Stipulating Parties agree that PGE should engage an outside consultant after December 31, 2012 to evaluate the efficacy of the mechanisms, inclusive of an evaluation of questions provided in Exhibit 501. Further, the Stipulating Parties agree that PGE will pay for the first $50,000 of study costs without seeking rate recovery of such amount. PGE will charge any costs above $50,000 to the decoupling balancing account.

Q. Please describe the stipulation regarding Sunway 3.

A. The Stipulating Parties agree that PGE should transfer the 2011 revenue requirement of the Sunway 3 investment from the Renewables Adjustment Clause (RAC) filing in UE 220 to this rate case. As demonstrated in Exhibit 502, the revenue requirement of Sunway 3 is $256,000.

Q. What is the basis for the stipulation regarding Sunway 3?

A. The stipulation provides for administrative simplification by placing all 2011 investment related revenue requirements in the rate case. If Sunway 3 remained in the RAC, and PGE did not file a rate case with a 2012 test year, PGE would be required to file an update of the Sunway 3 revenue requirement for 2012 pursuant to the terms of Schedule 122. The Stipulating Parties have reviewed the expected change of approximately $11,000 decrease in revenue requirement for Sunway 3 and found it immaterial.

Q. Please describe the final two adjustments to revenue requirements

A. As part of this settlement, in order to resolve all remaining issues, PGE agreed to make the following two adjustments:

- An adjustment to rate base to achieve a revenue requirement reduction of $100,000. Consistent with the cost of capital agreement detailed above, a reduction in rate base of $717,000, along with an associated reduction in depreciation of $16,000 creates the $100,000 reduction to 2011 test year revenue requirements, as demonstrated in Exhibit 502.
- A reduction in overall revenue requirement by $1 million. To obtain this result, the Stipulation Parties agree than PGE should increase its forecast of Other Revenue by $966,000 as demonstrated in Exhibit 502.

Q. Are there any other elements to this stipulation?

A. Yes, the Stipulating Parties also agreed that PGE should withdraw its application for deferred accounting related to 2010 pension costs in UM 1462.

Q. What is your recommendation to the Commission regarding all of these adjustments?

A. The Stipulating Parties recommend and request that the Commission approve the settlement described herein and in Exhibit 501. Based on careful review of PGE's and Parties' filings, consideration of PGE's responses to over 700 data requests, and thorough analysis of the issues before and during the July 22 settlement conference, we believe the proposed adjustments represent appropriate and reasonable resolutions of the respective issues in this docket. While the Stipulating Parties may not agree with the individual adjustments or necessarily the methodologies used by Parties to obtain them, the Stipulating Parties believe the collective result will produce rates that will be fair, just, and reasonable.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

Exhibit	Description
501	Stipulation on Cost of Capital, PCAM, and remaining revenue requirement issues.
502	PGE revised revenue requirement reflecting all stipulations.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 215

In the Matter of	)	
	)	
PORTLAND GENERAL ELECTRIC COMPANY	)	**STIPULATION REGARDING REMAINING ISSUES**
	)	
Request for a General Rate Revision	)	

This Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), Fred Meyer Stores and Quality Food Centers, Division of Kroger Co. ("Kroger"), and the Industrial Customers of Northwest Utilities ("ICNU")(collectively, the "Stipulating Parties").

On February 16, 2010, PGE filed this general rate case. On March 8, 2010, a prehearing conference was held. A procedural schedule was entered with separate schedules for the annual net variable power cost portion of the PGE's request and the other issues relating to the general rate revision. The docket has proceeded pursuant to those schedules. PGE has responded to numerous data requests in this docket from Staff and intervenors. Four prior Stipulations, three regarding revenue requirement issues and one regarding rate spread and rate design issues, have been submitted to the Commission.

On June 4, 2010, the Stipulating Parties other than PGE filed their respective direct testimony regarding revenue requirement issues. On July 19, 2010, PGE filed its rebuttal testimony regarding the issues that remained unsettled. On July 22, 2010, the Stipulating Parties participated in a Settlement Conference that resulted in a compromise settlement by the

Stipulating Parties regarding the remaining issues in this docket, as described below.

TERMS OF STIPULATION

I. This Stipulation is entered to settle all remaining issues among the Stipulating Parties in this docket excepting only the issue of the Boardman tariff reserved by ICNU and Kroger in the Second Revenue Requirement Stipulation.

II. Decoupling. The Stipulating Parties request that the Commission extend PGE's Schedule 123 decoupling tariffs beyond the two-year period specified in Order 09-020, through December 31, 2013. The Stipulating Parties agree that within 60 days after the fourth year of operation of PGE's Sales Normalization Adjustment and Lost Revenue Recovery decoupling tariffs, that the parties will confer to identify an independent consultant, for the purpose of examining the effectiveness of the decoupling tariffs. If the Stipulating Parties cannot agree on an independent consultant to perform this analysis they will ask the Commission to select the consultant. PGE will pay the first $50,000 of the costs of the consultant's analysis. Any expense beyond $50,000 will be included in the decoupling tariff balancing account. The consultant should, at a minimum, address the questions contained in Exhibit "A" to this Stipulation. The timeline for the consultant study should be such that the study is completed by the end of the fifth year of decoupling tariff operation. The Parties do not agree on the appropriate fixed cost recovery methodology, but agree that the Schedule 123 fixed cost recovery rate methodology currently in effect for PGE should be continued through December 31, 2013 in order to allow the independent consultant, identified above, to review that mechanism.

III. Rate of Return. The Stipulating Parties agree that PGE's authorized return on equity will be 10.0%, the same as currently authorized. PGE's capital structure for ratemaking purposes will remain at 50% common equity and 50% long-term debt. PGE's cost of long-term debt will be 6.065% as set forth in PGE's rebuttal testimony in this docket. The preceding values result in an overall cost of capital of 8.033%.

IV. PCAM. Effective for power costs beginning January 1, 2011, the power cost variance deadbands in PGE's Annual Power Cost Variance Mechanism tariff, Schedule 126, will be set as follows: The Negative Annual Power Cost Deadband will be $15 million. The Positive Annual Power Cost Deadband will be $30 million. The Stipulating Parties agree to no other changes in Schedule 126 in this docket; however, no party is precluded from proposing changes to Schedule 126 in future general rate cases.

V. Rate base and revenue requirement adjustments. In settlement of all issues, two adjustments will be made:

1. In calculating the revenue requirement resulting from this rate case only, PGE will remove an amount from rate base sufficient to result in a revenue requirement decrease of $100,000. This will be achieved by reducing rate base $717,000 and associated depreciation by $16,000.
2. In calculating the revenue requirement resulting from this rate case only, PGE will add $966,000 to "Other Revenues" to cause a decrease in revenue requirement of $1 million.

VI. Pension Deferral. PGE will withdraw its application for deferred accounting of certain pension expenses docketed as Docket UM 1462.

VII. Sunway 3. Sunway 3 is a solar generating project included in PGE's Renewable Resources Automatic Adjustment Clause filing, Docket UE 220. Sunway 3 will be operational and closed to PGE's books during 2010. The Stipulating Parties agree that the rate base and revenue requirement of Sunway 3 (approximately $262,000 in UE 220, which value will be updated to reflect the cost of capital provided in paragraph III above) be moved from Docket UE 220, and included in this general rate case. The Parties to Docket UE 220 have also agreed to move Sunway 3 to this docket.

VIII. The Stipulating Parties recommend and request that the Commission approve the adjustments described above as appropriate and reasonable resolutions of the remaining issues in this docket.

IX. The Stipulating Parties agree that this Stipulation is in the public interest and will result in rates that are fair, just, and reasonable.

X. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in the instant or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

XI. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order which is not contemplated by this Stipulation, each Stipulating Party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and OAR 860-014-0095, including the right to withdraw from the stipulation and to seek reconsideration of the Commission's order. Nothing in this paragraph provides any Stipulating Party the right to withdraw from this Stipulation as a result of the Commission's resolution of issues that this Stipulation does not resolve.

XII. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing (if necessary), and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting written testimony required by OAR § 860-14-0085(4).

XIII. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation, other than those specifically identified in the Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

XIV. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 2nd day of ~~July~~ August, 2010.

PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

CITIZENS' UTILITY BOARD
OF OREGON

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

THE KROGER CO.

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Exhibit "A"

Decoupling Mechanism Questions:

1. Did the mechanisms effectively remove the relationship between the utility's sales and profits?

2. Did the mechanisms effectively mitigate the utility's disincentives to promote energy efficiency?

3. Did the mechanisms improve the utility's ability to recover its fixed costs?

4. Did the mechanisms reduce business and other financial risks? If yes, please describe the business and financial risks that were impacted and the level of impact and effects on operations.

5. What changes in the Company's culture or operating practices resulted from the implementation of the partial decoupling mechanism?

6. To what extent did fixed costs covered by fixed cost-recovery factors increase with customer growth beyond what was included in the test-year load forecast in UE 197 and in any subsequent general rate case?

7. PGE's mechanism is based on a volumetric fixed charge. However, the amount of revenue available for fixed cost recovery may vary depending on the variable cost of the power being sold or purchased (Revenue/kWh minus variable power cost/kWh equals revenue available for fixed costs). Should the volumetric fixed charge decoupling rates be calculated in a different manner in order to account for this. For example, as the difference between total volumetric rates for both Schedules 7 and 32 and a measurement of short-run marginal energy costs such as the Mid-Columbia index?

8. What is the effect of a change in load (as included in this mechanism) on PGE's costs? What is the effect of the change in load on revenue? Has this mechanism accurately accounted for these changes? On a going forward basis is this mechanism likely to accurately account for these changes?

9. Should the SNA mechanism be bifurcated such that the total kWh for each of Schedules 7 and 32 are fixed for and beyond the test period for purposes of recovery/refund of transmission and generation fixed revenue requirements? Calculation of the fixed revenue requirements for functions other than generation and transmission would be in the same manner as is currently done.

Portland General Electric Company
2011 Test Year Rate Case, NVPC per July 30 Update
Exhibit 502 - Joint Testimony in Support of Cost of Capital Stipulation
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	(57,504)	(17,332)	1,736,160
Sales for Resale	-		-			-	-	-	-
Other Revenues	20,961		20,961			20,961	2,078	-	23,040
Total Operating Revenues	927,087	779,727	1,706,814	157,679	(32,535)	1,831,958	(55,426)	(17,332)	1,759,200
Net Variable Power Costs		747,192	747,192			747,192	19	(16,670)	730,541
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	(246)	(99)	9,896
OPUC Fees	5,268		5,268	391		5,659	(135)	(54)	5,426
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	(21,851)	(16,823)	1,125,656
Depreciation	216,287		216,287			216,287	(8,459)	-	207,829
Amortization	16,277		16,277			16,277	663	-	16,940
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	(1,079)	(433)	43,387
Utility Income Tax	5,547	12,707	18,255	59,900	(12,707)	65,447	(8,132)	(22)	57,293
Total Operating Expenses & Taxes	751,766	759,899	1,511,666	64,154	(12,707)	1,563,112	(39,063)	(17,278)	1,505,960
Utility Operating Income	175,321	19,828	195,149	93,525	(19,828)	268,846	(16,363)	(54)	253,240
			195,149			268,846			253,240

Portland General Electric Company
2011 Test Year Rate Case, NVPC per July 30 Update
Exhibit 502 - Joint Testimony in Support of Cost of Capital Stipulation
Dollars in 000s

	Non-NVPC Results (1)	NVPC Results (2)	Total Results Before Price Change (3)	Non-NVPC Price Change (4)	NVPC Price Change (5)	Total Results After Price Change (6)	Non-NVPC Adjustments (7)	NVPC Adjustments (8)	Rev Rev w/Adjustments (9)
Average Rate Base									
Avg. Gross Plant	6,491,337		6,491,337			6,491,337	(96,677)	-	6,394,660
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)	4,479	-	(349,488)
Avg. Accum. Def ITC	(5)		(5)			(5)	-	-	(5)
Avg. Net Utility Plant	3,113,416	-	3,113,416	-	-	3,113,416	(87,213)	-	3,026,203
Misc. Deferred Debits	47,251		47,251			47,251	(1,469)	-	45,782
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	(1,523)	(674)	58,732
Average Rate Base	3,241,595	-	3,241,595	2,006	-	3,243,601	(90,205)	(674)	3,152,690
Rate of Return	5.408%		6.020%			8.289%			8.033%
Implied Return on Equity	4.740%		5.963%			10.500%			10.000%
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%	10.000%	10.000%	10.000%
Grossed-Up COC	11.653%	11.653%	11.653%	11.653%	11.653%	11.653%	11.237%	11.237%	11.237%
OPUC Fee Rate	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%	0.3125%

Portland General Electric Company
2011 Test Year Rate Case, NVPC per July 30 Update
Exhibit 502 - Joint Testimony in Support of Cost of Capital Stipulation
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	(55,426)	(17,332)	1,759,200
Book Expenses	746,219	747,192	1,493,411	4,254	-	1,497,665	(31,742)	(17,256)	1,448,667
Interest Deduction	98,496	-	98,496	61	-	98,557	(2,735)	(20)	95,605
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	11,894	(55)	99,235
Current State Tax	(4,130)	2,031	(2,099)	9,573	(2,031)	5,443	742	(3)	6,194
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	742	(3)	2,495
Federal Taxable Income	(58,334)	30,504	(27,830)	143,791	(30,504)	85,457	11,151	(52)	96,739
Current Federal Tax	(20,417)	10,677	(9,740)	50,327	(10,677)	29,910	3,903	(18)	33,859
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	(8,208)	(22)	57,293
SB 408 Ratio - Net to Gross	19.96%	39.06%	12.66%	39.06%	39.06%	18.46%	39.18%	39.06%	17.89%
SB 408 Ratio - Effective Tax Rate	3.07%		8.55%			19.58%			18.45%
Check SB 408 Calc	-		-			-			0
Regulated Net Income	76,825		96,653			170,289			157,635
Check Regulated NI						170,289			157,635

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **JOINT TESTIMONY IN SUPPORT OF THE STIPULATION REGARDING REMAINING ISSUES FILED AUGUST 2, 2010** 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 9th day of August, 2010.

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