ENTERED 01/22/2009

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 197

In the Matter of	)	
	)	
PORTLAND GENERAL ELECTRIC COMPANY,	)	ORDER
	)	
Request for a general rate revision.	)	

I. INTRODUCTION

This order completes our review of a request for a general rate increase filed by Portland General Electric Company (PGE or the Company). Exclusive of net variable power costs (NVPC), PGE originally sought a general rate increase of $93.6 million in general revenues. Based on our decisions in this order, we authorize PGE to increase its revenues for non-NVPC-related costs by $25.6 million. Combined with our earlier decision approving a stipulation resulting in a total increase of $95.4 million in NVPC-related revenue requirement,[1] this order results in an overall increase in revenues by approximately $121.0 million, effective January 1, 2009. This translates to an approximate 7.6 percent rate increase overall for PGE's customers.

Due to applicable statutory deadlines, we needed to resolve PGE's request by the end of 2008. But the broad scope of the case, as well as unusual weather-related delays and other scheduling difficulties, made it difficult to issue a comprehensive order by this deadline. We therefore issued two preliminary orders. In the first, we addressed rate spread and rate design issues.[2] In the second, we summarized our resolution of all issues presented by the parties in this proceeding.[3]

In this final order, we provide further background regarding the issues, including the parties' positions, and provide our analysis and conclusions. We also reaffirm the findings and conclusions in Order Nos. 08-585 and 08-601.

[1] *See* Order No. 08-505, Docket No. UE 198 (Oct. 21, 2008). At the December 23, 2008, Public Meeting, the Commission approved PGE's final 2009 net variable power costs that were $42.4 million higher than the Company's original requested increase of $53.0 million. *Also see* Issue S-15 [reference table on page 31]. The result is a total increase of $95.4 million in NVPC-related revenue requirement.
[2] Preliminary Order No. 08-585 (Dec. 15, 2008). An *Errata*, Order No. 09-006 (Jan. 12, 2009) replaced a document erroneously appended to the order.
[3] Preliminary Order Setting Rates, Order No. 08-601 (Dec. 29, 2008).

II. PROCEDURAL BACKGROUND

On February 27, 2008, PGE filed Advice No. 08-02, an application for approval of revised tariff schedules, docketed as UE 197. PGE requested a $145.9 million (9.2 percent) increase in revenues. Approximately $93.6 million of the request was unrelated to NVPC (5.9 percent). PGE's application also included the annual filing required by PGE's annual update tariff (Schedule 125), as well as other proposed changes related to NVPC and the annual update process that may only be made in a general rate proceeding.

At the March 25, 2008, Public Meeting, we found good cause to investigate PGE's application and suspended Advice No. 08-02 pursuant to ORS 757.215. Because we determined that the rate investigation could not be completed within a six-month suspension period, we ordered that the tariffs be suspended for a total period of nine months from March 31, 2008.[4] The rates will go into effect on January 1, 2009.

The following parties intervened and participated in this docket: the Citizens' Utility Board of Oregon (CUB); the Industrial Customers of Northwest Utilities (ICNU); Fred Meyer Stores and Quality Food Centers, Divisions of Kroger Co. (Kroger); the Community Action Directors of Oregon and Oregon Energy Coordinators Association (CADO/OECA); the Oregon Department of Energy (ODOE); and the League of Oregon Cities (LOC). Public comment hearings were held on July 8 and July 9, 2008, in Portland and Salem, respectively.

During a prehearing conference on March 21, 2008, all parties agreed to bifurcate docket UE 197 and create a separate docket, designated as docket UE 198, to address issues related to PGE's NVPC. Ultimately, issues related to PGE's NVPC were resolved by the adoption of a stipulation among the parties in Order No. 08-505, entered October 21, 2008. All other issues related to PGE's general rate revision are addressed in this order.

Pursuant to the procedural schedule established for this docket, Staff and intervenors filed direct testimony in July 2008, and PGE filed rebuttal testimony on August 15, 2008. Staff and intervenors filed surrebuttal testimony on September 15, 2008, and PGE filed sur-surrebuttal testimony on October 1, 2008. An evidentiary hearing was held on October 10, 2008, after which the record in the proceeding was closed. All parties filed simultaneous opening briefs on October 24, 2008, and reply briefs on November 4, 2008.

[4] *See* Order No. 08-184 (Mar. 31, 2008).

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

We divide our discussion into three primary parts. First, we address three stipulations submitted by the parties. Second, we address the contested issues. Third, we summarize the results of all the decisions in this docket and their impact on PGE's revenues and customer rates.

A. STIPULATED ISSUES

1. Revenue Requirement

PGE entered into two stipulations with other parties to resolve various issues primarily related to the Company's revenue requirement. Copies of the two stipulations are attached as Appendix A. The stipulating parties have requested that we approve the adjustments that they have proposed as appropriate and reasonable resolutions of these issues. They further agree that the stipulations are in the public interest and will result in rates that are fair, just, and reasonable and that the terms of the stipulations represent a compromise in the parties' positions. No non-signatory party to the proceeding filed any written objection to either stipulation under OAR 860-014-0085(5).

PGE filed the Stipulation Regarding Revenue Requirement Issues (First Stipulation), together with supporting testimony (Staff-CUB-PGE/100), on August 5, 2008. The First Stipulation was signed by PGE, Staff, CUB, ICNU, ODOE, and Kroger, and proposed a revenue-requirement reduction of approximately $13.6 million from PGE's initial rate filing.[5] A summary of the components of the First Stipulation, divided by issue, is as follows:

<u>Rate of Return (Issue S-0)</u>: The stipulating parties agree that PGE's authorized return on equity (ROE) should remain at the currently authorized level of 10.1 percent, and PGE's capital structure for ratemaking purposes should remain unchanged at 50 percent equity and 50 percent debt. The parties also agree that PGE's cost of debt should be 6.567 percent, as set forth in PGE's initial filing in this docket. These changes result in a revenue-requirement decrease from PGE's original request of approximately $12.9 million.

<u>Other Electric Revenues (Issue S-1) and Schedule 300 (Issue S-17)</u>: The stipulating parties agree that PGE's forecast of other revenues should be decreased by $445,000 as a result of the change in proposed Schedule 300 rates, as well as changes to additional "other electric revenue" items. The stipulating parties agree that PGE's proposed increases to Schedule 300 rates should not be adopted, but should remain as they are in PGE's current tariff.

[5] The parties were unable to determine the precise amount of the adjustment because it was dependent, in part, on revenue-sensitive factors that were not included in the First Stipulation.

Lease Adjustment (Issue S-6), Fuel Adjustment (Issue S-7) and Membership Adjustment (Issue S-8): In support of the overall settlement, Staff agrees to withdraw its proposed adjustment to these three items.

Kelso-Beaver Pipeline (Issue S-12): The stipulating parties agree that PGE's forecasted Operation and Maintenance (O&M) expense for the pipeline should be reduced by $1.0 million.

Rate Base True-ups for Biglow Canyon Phase 1 and Port Westward (Issue S-18): The stipulating parties agree that the rate base amounts for Biglow Canyon Phase I and Port Westward should be trued-up to actual 2007 year-end net investment balances, resulting in a $735,000 reduction in PGE's forecast of average 2009 rate base and a $24,000 reduction in its estimate of 2009 book depreciation expense. These changes result in a revenue-requirement decrease of approximately $113,000.

PGE filed the Second Stipulation Regarding Certain Revenue Requirement and Tariff Issues (Second Stipulation) on October 9, 2008. The Second Stipulation was signed by PGE, Staff, CUB, and ICNU and included an additional $13.2 million revenue-requirement reduction. A summary of the components of the Second Stipulation, divided by issue, is as follows:

Research and Development (Issue S-2): The stipulating parties agree that PGE's test-year O&M expenses for research and development should be reduced by $650,000.

Capital Additions (Issue S-5): In its initial filing, PGE had proposed certain capital additions to the Boardman generating plant, the Clackamas relicensing project, and the Selective Water Withdrawal (SWW) facility at Pelton-Round Butte. As part of the stipulation, Staff agrees to drop its objections to the Boardman capital additions. The stipulating parties also agree with the position set forth in PGE's rebuttal testimony regarding the Clackamas relicensing and the combined adjustments removing both the Clackamas relicensing and the SWW from the revenue requirement under the following conditions:

- The $65.968 million of average rate base ($63.25 million for the SWW project and $2.717 million for Clackamas relicensing) are removed. The associated depreciation expense of $2.039 million (solely attributable to SWW) and property tax expense of $1.049 million ($1.006 million for SWW project and $0.43 million for Clackamas relicensing) are also removed.

- The inclusion in rates of the SWW project capital additions and related expenses including depreciation and property tax expense will be addressed in a separate docket.[6]

WECC Reliability Center (Issue S-10) and NERC/WECC Consultant, RCM Program Costs (Issue S-13): The stipulating parties agree that certain O&M expenses for the WECC Reliability Center and related regional transmission planning and flow mitigation should be reduced by $150,000. The parties also agree that the combined test-year O&M expenses for a NERC/WECC Consultant, RCM program costs, and miscellaneous software upgrades should be reduced by $200,000.

Revenue-Sensitive Costs (Issue S-16): The stipulating parties agree to an uncollectible rate of 0.43 percent, as proposed by PGE. The resulting effect on the revenue requirement is estimated at $0.9 million.

Energy Audits (Issue S-19): The stipulating parties agree that the test-year revenue requirement for customer accounting O&M expenses should be decreased by $0.15 million.

Schedule 129: The stipulating parties also agree to certain changes to Tariff Schedule 129, Long-Term Transition Cost Adjustment, as set out in PGE/2001, Kuns-Cody-Lynn/4. This schedule is only applicable to large non-residential customers and now includes an annual cap on the percent change in customer impacts for customers that have selected service under Schedules 83 and 89.

2. Rate Spread and Rate Design

PGE also entered into the Stipulation Regarding Rate Spread and Rate Design (Third Stipulation) with CUB, ICNU, and Kroger, which was filed October 8, 2008. With one exception, the stipulating parties agree that the marginal cost study and rate design principles established in Commission dockets UE 115 and UE 180 would continue to be used for this case. The agreed-upon exception was the parties' agreement to changes to rates charged under Schedules 83-P and 83-S.

3. Resolution

Upon review of the First and Second Stipulations and supporting testimony and explanatory statements, we find that the stipulating parties have complied with the requirements of OAR 860-014-0085(4) and conclude that the stipulations will result in rates that are fair, just, and reasonable. We find the provisions of the First and Second Stipulations are in the public interest and adopt them. Combined, these two stipulations reduce PGE's non-NVPC revenue-requirement request of $93.6 million by $26.7 million, resulting in a revised revenue-requirement increase of $66.9 million.

[6] At its November 4, 2008, Public Meeting, the Commission suspended the PGE proposed tariff sheets on the SWW project capital additions and designated them for investigation in docket UE 204.

In Order No. 08-585, we addressed the reasonableness of the Third Stipulation and adopted it. We also agreed with the stipulating parties' recommendation to open a separate proceeding to address rate spread and rate design issues for PGE and its customers. We incorporate our findings and conclusions here.

B. CONTESTED ISSUES

While the parties were able to settle many of the issues presented in this proceeding, the following contested issues remain for our resolution. We address each issue separately.

1. CUB's Proposed Overall 1 Percent Reduction in PGE's Revenue Requirement

We begin with CUB's generalized assertion that PGE's O&M expenses are too high. Based on its apparent conclusion that some costs are imprudent, CUB requests that the Commission decrease PGE's revenue-requirement request by a flat 1 percent. CUB argues that PGE's application "provides little or no rational justification for the general non-power cost portion of the tariff adjustments it seeks," that improper calculations and shifting theories have frustrated other parties, and that PGE has failed to meet its burden of proof to show its rates are just and reasonable.[7] Thus, CUB proposes that, in lieu of the individual adjustments discussed below, the Commission should impose a 1 percent revenue-requirement reduction (approximately $17 million), over and above the reductions contained in the First and Second Stipulation.

Resolution

We reject CUB's alternative recommendation for two reasons. First, the request is arbitrary. We cannot impose a disallowance based on a generalized and unsubstantiated assertion as to PGE's O&M expenses. Second, CUB's request has been mooted by our examination of the major O&M cost categories and our adoption of individual adjustments based on evidence in the record.

2. Workforce Adjustment (Issue S-3) and Wage & Salary Adjustments: Number of Full-Time Employees, Wage Escalation Factors, and Officer Salaries (Issue ICNU/CUB-1)

A fundamental disagreement in this case is what approach should be used to determine total wages and salaries for the 2009 test period. PGE states that the Company's revenue-requirement request is a function of the number of full-time equivalent employees (FTEs) and the pay structure. The Company's initial filing indicated an increase of 130 positions from 2007 to the 2009 test period, citing

[7] CUB Opening Brief at 2-6, 54.

additional regulatory requirements, new generating plants, growth in customer base, and efforts to reduce overtime. PGE asserts that its pay structure is market based.[8]

Staff proposes a workforce level adjustment based on average annual historical growth in FTEs.[9] Staff states that the Commission's role should not be to micromanage PGE's operations, but to instead set an appropriate workforce level and allow the Company to establish priorities. ICNU and CUB recommend that the Commission set wage and salary costs using escalated historical results of operations, stating that PGE's "bottom-up budget process" should be rejected because there is no evidence that the wage escalations or FTE counts are reasonable. They argue that the FTE numbers are inflated and historically over-budgeted and should instead be escalated by historical averages.[10] They recommend a payroll adjustment using lower FTE and wage levels.[11]

PGE responds that test-period FTE levels must be based on known and measurable changes in the resources needed to provide safe, reliable power and meet all PGE's regulatory and compliance requirements.[12] PGE calculated two corrections to Staff's method that produced adjustments of $2.0 million and $4.2 million.[13]

Resolution

We reject PGE's proposed incremental approach to calculating test-year FTEs. To do a proper analysis, we would have to evaluate all 2,600-plus positions in the Company and not just the incremental positions PGE proposes to add. We will not take the existing positions as a given without such an analysis. Nor do we find such an analysis practical or good policy. We adopt Staff's approach applying the historical growth rate in workforce levels. Ultimately, the Company may choose to hire whatever staff or fill whatever positions it feels is necessary.

Therefore, for non-officers, we will escalate the 2007 FTE level by the Company's historical FTE growth rate and multiply it by the appropriate 2009 average wage levels to set the authorized straight-time wages and salaries for the test period. We will then combine this amount with a reasonable level for officers' salaries and compare the result to PGE's proposed 2009 total wages and salaries to determine what adjustment is appropriate.[14] We address each of these sub-issues below.

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[8] PGE/800, Barnett-Bell/5.
[9] Staff/807, Owings/1.
[10] *See* ICNU-CUB/111, Blumenthal/5.
[11] CUB Opening Brief at 9-13 and testimony cited therein; ICNU-CUB/113, Blumenthal/1.
[12] PGE/1400, Tooman-Tinker/7.
[13] PGE/1400, Tooman-Tinker/10; PGE/2300, Tooman-Tinker/15.
[14] During the course of this proceeding, PGE proposed total 2009 test-period FTEs of 2,706 after removing 30 unfilled FTEs from the errata-adjusted filing total of 2,736. PGE/1400, Tooman-Tinker/10, 15. We do not adopt this adjustment. Instead, we compare our calculation of 2009 total wages and salaries to PGE's proposed total wages and salaries in its initial errata-adjusted filing.

a. Number of Full-Time Employees

We first identify the number of FTEs in the 2007 base year. According to PGE, an FTE is not a single person who is employed full time, but rather a function of hours worked per year. According to PGE's witness, "FTEs are something we derive from the forecasted hours needed to perform the work."[15] Thus, overtime work can accumulate to form FTEs although the forecast of the number of actual employees to be newly hired has not risen proportionally. PGE indicates that the number of 2007 FTEs is 2,612, including FTE-equivalents for exempt employees' overtime.[16]

Staff, ICNU, and CUB propose that exempt overtime hours should be excluded from the FTE count. These parties point out that exempt employees are not eligible for payment of overtime, so when an exempt employee works overtime hours, the employer does not pay any additional amount for overtime work.[17] The parties note that when overtime for exempt employees is excluded, PGE's 2007 FTE count is 2,560.[18]

Resolution

We concur with Staff, ICNU, and CUB that exempt overtime should not be included in the baseline estimate, and we therefore adopt 2,560 FTE for the FTE baseline value. For the three non-officer categories, the result is a starting point of 1,153 Exempt, 584 Hourly, and 809 Union employees.[19]

b. FTE Escalation Rate

We next address the appropriate FTE escalation rate. The 2007 FTE levels should be increased by PGE's historical growth rate for FTEs. PGE corrected Staff's original calculation of the average annual growth rate for 2004 through 2007 to 1.45 percent.[20] Staff accepts this figure.[21]

Resolution

We adopt 1.45 percent as the average annual growth rate to increase 2007 non-officer FTEs to 2009. The result is a head count of 2,621 non-officer employees, a 75 FTE increase over 2007, for calculating test-period wages and salaries.

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[15] Hearing Tr. at 48, lines 2-3 (Oct. 13, 2008).
[16] PGE/1400, Tooman-Tinker/8; PGE/2300, Tooman-Tinker/11.
[17] ICNU Opening Brief at 12; Staff Reply Brief at 2.
[18] Staff Opening Brief at 4; ICNU-CUB/112, Blumenthal/12.
[19] *Id*.
[20] PGE/1400, Tooman-Tinker/9.
[21] Staff/800, Owings/15.

c. Wage Escalation Factors

Our calculation of PGE's test-period wages and salaries must escalate average 2007 non-officer wages to 2009. In its direct case, PGE forecast a 4.5 percent annualized increase in 2009 non-officer wages and salaries, asserting:

> PGE's philosophy is to provide compensation sufficient to attract and retain employees necessary to provide safe and reliable electric service at a reasonable price with outstanding customer service. At the same time, PGE actively controls costs by targeting our compensation program attributes and costs to reflect market median conditions. As market practices change, PGE responds to ensure that our total compensation package is competitive and generally tracks the market.[22]

In so doing, PGE claims that it relies upon internal studies and review of Bureau of Labor Statistics studies[23] and surveys conducted by the Economic Research Institute.[24] PGE also provided a table on the U.S. Economic Outlook for Inflation, prepared by *Global Insight* in June 2008. That table showed annualized increases in wages and salaries for 2008 and 2009 as 3.1 and 2.8 percent, respectively, substantially less than the 4.5 percent increase requested by PGE for 2009 non-executive labor.[25]

ICNU, with whom CUB conditionally concurs, argues that the PGE-proposed labor escalation rates of 6.0 percent, 4.5 percent, 4.5 percent, and 4.0 percent for the four major groups of employees—officers, exempt, hourly, and union, respectively—should be rejected. ICNU proposes increases of 0.0 percent, 2.0 percent, 3.0 percent, and 2.0 percent for the respective employee groups.[26] ICNU cites PGE testimony regarding retirement eligibility of higher paid employees, the tightening job market caused by the current financial conditions, and rising unemployment in Oregon that will likely make it easier for PGE to hire replacement workers than originally forecast.[27]

In response, PGE identified several "significant problems" with ICNU's analysis, asserting that the wage adjustments selectively excluded unusual historical wage increase information and ignored historical data in favor of anecdotal information. The Company referred to a market survey from the Economic Research Institute and stated that the ICNU proposal would place PGE at a disadvantage in hiring and retaining qualified individuals.[28]

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[22] PGE/800, Barnett-Bell/2.
[23] *Id.* at 6.
[24] PGE/2400, Barnett-Bell/6.
[25] PGE/1903, Piro-Tooman/2; PGE/200, Tooman-Tinker/5.
[26] ICNU Opening Brief at 15-16.
[27] *Id.* at 17.
[28] PGE/2400, Barnett-Bell/4-6.

Resolution

Historically, the Commission has used a three-year wage and salary formula to escalate utility wages. The formula reflects two components: (a) inflation, and (b) real escalation, indicating, in part, market conditions.[29] Using that as our template, we adopt use of the All-Urban CPI Core Index from the June 2008 *Global Insight* report for inflation, which forecasts inflation increasing at 2.4 percent in 2008 and 2.4 percent in 2009.[30] In light of the current economic situation, we choose not to adopt a real escalation factor. We therefore authorize an increase in average non-officer wages and salaries that reflects an annualized growth in exempt, hourly, and union wages and salaries of 2.4 percent for 2008 and 2.4 percent for 2009.[31]

d. Number of Officers

PGE included salaries for 12 officers in the 2009 test period.[32] One of those officers has been loaned out to another organization, and there is no plan for replacement; those duties are being performed by other managers.[33] ICNU argues that the officer count should be reduced from 12 to 11 and that one-twelfth of total officers' salaries, approximately $287,000, should be removed from the revenue-requirement calculation.[34]

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[29] *See* Order No. 95-322 at 9-10 (Docket No. UE 88), Order No. 99-697 at 43 (Docket No. UG 132), and Order No. 01-787 at 39-40 (Docket No. UE 116).
[30] PGE/1903, Piro-Tooman/2.
[31] We note the following actual number of employees by class and their straight-time wages and salaries for the year 2007 and calculate an average wage or salary per employee:

EMPLOYEE CLASS	*EXEMPT*	*HOURLY*	*UNION*
Actual FTEs	1,153	584	809
Wages & Salaries	$100,248,092	$23,790,819	$54,466,831
W&S/Employee	$86,945.44	$40,737.70	$67,326.12

The following table applies our decisions to calculate PGE's allowable 2009 test-year wages and salaries for non-officers; *i.e.*, the 1.45 percent annual FTE growth rate and 2.4 percent wage escalators for both 2008 and 2009:

EMPLOYEE CLASS	*EXEMPT*	*HOURLY*	*UNION*
2009 FTEs	1,187	601	833
2009 W&S/Employee	$91,168.90	$42,716.57	$70,596.55
2009 W&S Rev. Req.	$108,217,484	$25,672,659	$58,806,926

[32] PGE/1402, Tooman-Tinker/3.
[33] Tr. at 25, lines 14-15.
[34] ICNU Opening Brief at 15.

Resolution

We reject ICNU's recommendation to reduce the number of officers from 12 to 11. PGE historically has had 12 or more officers, and we will make no adjustments to PGE's request.

e. Officer Salaries

PGE officers earned salaries totaling $3,174,109 in 2007.[35] In 2008, budgeted officer salaries were $3,250,392, a 2.4 percent increase over 2007.[36] For 2009, PGE proposes to increase officer salaries by 6.0 percent to a total of $3,445,416 for 12 officers.[37] With respect to per-officer compensation levels, PGE states that its officer salaries were well below market under the Enron bankruptcy case, and an independent expert was hired in 2006 to do a market analysis using an executive survey and 14 company comparators. As a result of that analysis, PGE increased compensation for officers to "almost market."[38]

ICNU contends that increases in compensation for officers should be at shareholder expense.[39] ICNU notes that PGE's Chief Executive Officer received total compensation approaching $2.8 million in 2007, and that average total compensation for PGE's top six officers was $880,288, much higher than the compensation of officers at Northwest Natural Gas Company and PacifiCorp. CUB concurs in the testimony of ICNU witness Blumenthal opposing compensation increases for PGE's officers.[40]

Resolution

We find that PGE has not justified an increase in officer compensation over 2008 levels. PGE witnesses state that national compensation surveys place its officers' salaries near market. Also, PGE's witness acknowledged that the salaries of other Oregon utility executives were used as salary benchmarks and were below PGE officer salaries. Therefore, we find that PGE has failed to justify any increase in compensation above budgeted 2008 officer salaries. We reduce PGE's officer salaries in the test period by $0.2 million from the Company's forecast of $3,445,416.

Summary

In light of our decisions above, we conclude that PGE's revenue-requirement increase request with respect to officer and non-officer wages and salaries should be reduced by $15.8 million, including payroll loadings.

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[35] ICNU-CUB/104, Blumenthal/3.
[36] Calculated as $3,445,416 from PGE/1402, Tooman-Tinker/3, less 6.0 percent executive labor escalation from PGE/200, Tooman-Tinker/5.
[37] PGE/1402, Tooman-Tinker/3.
[38] Tr. at 22-23.
[39] ICNU Opening Brief at 22-23 and testimony and exhibits cited therein.
[40] CUB Opening Brief at 16-17.

3. Corporate Incentives (Issue S-4)

a. Officer Incentive Compensation

In rebuttal testimony, PGE removed all officer incentive compensation from its revenue-requirement request. PGE also removed the officer vehicle plan and executive financial planning functions and associated costs from the test year, lowering costs by $135,000. PGE removed retired officer life insurance, a $9,315 reduction.[41] PGE has removed all officer incentive compensation, both the Annual Cash Incentive (ACI) and Stock Incentive Plan (SIP), totaling $3.4 million, and all director compensation ($0.3 million), from its proposed test-year revenue requirement.[42] Although not included as part of any stipulation, neither Staff nor any intervenor opposes the reduction.

Resolution

The Commission adopts a reduction of $3.9 million in the Company's proposal for officer incentive compensation and director compensation.

b. Non-Officer Incentive Compensation

In its 2009 test-year revenue requirement, PGE proposes $1,132,765 for non-officer SIP and $3,443,936 for ACI. In addition, PGE proposes $6,093,815 for the Corporate Incentive Plan (CIP) and $200,000 for Notable Achievement Awards (Notables), for total non-officer incentives of $10,870,516.[43] PGE asserts that the ACI and CIP awards are structured primarily to align the incentives with customer benefits; only 30 percent is allocated to "financial strength."[44] Notables reward extraordinary effort, serve to motivate employees, and are not tied to financial performance or profitability.[45]

After removing adjustments for proposed workforce reductions and in addition to removing 100 percent of the SIP because it is based solely on financial performance, Staff asserts that it is appropriate to allow 50 percent of ACI, CIP, and Notables because of the closer alignment to customer benefits. Staff also proposes an allocation of 28.25 percent to capital and 71.75 percent to O&M. The effect of Staff's recommendations is a downward adjustment of $6.9 million in PGE's revenue requirement.[46]

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[41] PGE/1500, Barnett-Bell/3.
[42] PGE/1400, Tooman-Tinker/5; PGE/1500, Bell-Barnett/3.
[43] PGE/1500, Barnett-Bell/7.
[44] PGE/800, Barnett-Bell/9; PGE/1500, Barnett-Bell/9; PGE/2400, Barnett-Bell/8.
[45] PGE/800, Barnett-Bell/11.
[46] Staff Opening Brief at 7 and testimony cited therein.

ICNU contends that ACI and SIP costs should be removed and remaining non-officer incentive costs should be shared equally between ratepayers and stockholders.[47] CUB proposes that the Commission allow only a 50/50 split between shareholders and ratepayers for the non-officer incentive compensation.[48]

Resolution

We agree with Staff, ICNU, and CUB that ratepayers benefit only in part from non-officer incentives. Accordingly, we conclude that an allowance of 50 percent of such costs into the revenue requirement is a fair approximation of the benefit to ratepayers. We disallow $5.7 million in non-officer incentives from PGE's proposal. Combined with the adjustment to Officer Incentives, this yields a total corporate incentives decrease of $8.07 million in PGE's 2009 revenue requirement.

c. Employee Discount

PGE provides a 25 percent discount on electricity service to active employees and to retired employees or their surviving spouses. It provides a 12.5 percent discount to part-time employees. In 2007, slightly more than two-thirds of the benefit recipients were active employees, and the cost of the program was $767,406. PGE proposes a cost of $885,846 to be included in the 2009 test-year revenue requirement.[49] According to PGE, PacifiCorp and Northwest Natural Gas Company, who compete with PGE for employees, also provide their employees with discounted service, as do other industries, as a comparatively low-cost means of compensation. PGE asserts that providing an employee discount is less expensive than an equivalent cash benefit that would have to be grossed up for taxes.

ICNU, CUB, and CAPO/OECA propose elimination of the employee discount. ICNU contends that the discount is discriminatory because not all PGE employees live in its service territory and because it creates a separate customer class not included in its tariffs. ICNU also asserts that PGE has not met its burden to show that the expense is a reasonable and necessary cost of providing service to customers, that the discount partially insulates its employees from rate increases affecting other customers, and that the discount does not promote conservation among eligible employees.[50] CUB claims the subsidy is unfair, noting that, in 2007, the average wage of subsidy-eligible employees was $75,764 and the average customer income in Oregon was $34,784. CAPO/OECA asserts that, if PGE wants to continue the subsidy, it should be shareholder-funded and that a third-party study might be undertaken to determine if the subsidy inhibits conservation.[51]

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[47] ICNU Opening Brief at 20-21 and cases and testimony cited therein.
[48] CUB Reply Brief at 9.
[49] PGE/1500, Barnett-Bell/26; ICNU-CUB/100, Blumenthal/14 at 10-13.
[50] ICNU Opening Brief at 21.
[51] CAPO/100/Abrahamson/3.

Resolution

PGE has long offered an employee discount as part of its incentive structure. In light of this longstanding practice, and given our decision on overall wages and salaries, we retain the employee discount for rate purposes.

4. Administration and General Expenses (Issue S-9, Part 1)

a. Payroll Loading Rate

A company's "loading rate" consists of the benefits, payroll taxes, other incentives, and the various departments and infrastructure that support the provision of employee-related activities of the corporation divided by the total wages and salaries paid. This calculation is at issue because ICNU has asserted that PGE's loading rate is excessive.

ICNU argues that PGE's proposed loading rate should be reduced, because incentive compensation and employee support costs are not demonstrably variable with payroll and are double counted as administrative and general costs.[52]

In response, PGE asserts that:

> [P]ayroll-related costs . . . (payroll taxes, employee benefits, incentives and employee support) are not included in this case through application of the loadings rate. Instead, each amount is directly forecasted. The loadings rates are then a derivative of these costs and not vice versa. Accordingly, adjustments for payroll-related costs should be made directly and not through a loadings rate adjustment, as ICNU does.[53]

Resolution

In this order, we do not address PGE's test-year, employee-related costs in its proposed revenue requirement through an examination of loading rates per employee. Rather, we review each contested component of the employee-related costs; *e.g.*, non-officer incentives, for their appropriateness. Those costs that are directly tied to the number and wage and salary levels of PGE's employees, such as payroll taxes, are simply accounting calculations and not a subject for our review. We therefore do not make any adjustments to the 2009 revenue requirement on the basis of a loadings rate calculation.

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[52] ICNU Opening Brief at 19.
[53] PGE Reply Brief at 14.

b. Medical Expense Level and Rate of Increase for Union Active Employees and Retirees

In 2007, PGE booked $1,199,155 for retiree medical and dental benefits and $9,235,367 for active union employees. PGE proposes a 10 percent escalation factor.

Staff asserts that PGE's proposed 10 percent escalation factor is too high and is unsupported. Staff argues that its proposed 8.5 percent escalation factor is more appropriate.[54] Staff also contends that the calculation of the increase in the medical and dental benefit to active union employees should apply to only ten months of the test year because the existing contract expires at the end of February 2009.[55]

Resolution

According to PGE, health insurance premiums were forecasted to increase by 4.2 percent in 2008 and 3.8 percent in 2009, resulting in a combined 8.16 percent increase over 2007.[56] As Staff notes, its proposed escalation factor of 8.5 percent for union benefits was at "the high end of projected rate increases based on recent studies concerning benefit costs."[57] Although PGE cites circumstances where it might be necessary to provide additional funding beyond its current obligations under extreme conditions, it offered no evidence to indicate that the feared confluence of events may be imminent. We therefore adopt the Staff analysis and calculations.[58] We find a 2009 active union benefit amount of $10,599,315 and add forecasted union retiree benefits of $814,000, as projected by PGE. The result is a downward adjustment of $685,000 to PGE's proposed 2009 revenue requirement.

5. Operation & Maintenance and Customer Service Expenses (Issue S-9, Part 2)

a. Tree Trimming Expenses

PGE seeks recovery of $12.3 million in tree trimming expenses. PGE explains that this amount provides funding primarily for 38 two-person crews, 3 three-person climbing crews, and 12 full-time flagging crews to complete scheduled trimming and other vegetation maintenance along its distribution lines.

Staff proposes to reduce PGE's tree-trimming expenses by approximately $1.3 million. Staff contends that PGE's request is inflated for two reasons. First, Staff states that PGE's forecast fails to reflect the fact that its actual tree trimming costs per line mile has decreased substantially, from $2,532 in 2007 to a forecasted $2,100 in 2009. Second, although PGE now admits that its original estimate of line miles was overstated

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[54] Staff/300, Ball-Dougherty/3; Staff/900, Ball/3.
[55] Staff/900, Ball/3-4.
[56] PGE Exhibit/1903/Piro-Tooman/2, citing *Global Insight* June 2008 U.S. Economic Outlook.
[57] Staff/900, Ball/3.
[58] *See* Staff Reply Brief at 6-7 and testimony cited therein.

by approximately 400 miles, the Company made no adjustment to reduce its request to account for the error. Staff recommends PGE be allowed to recover a total of $11 million in tree trimming expenses, a figure derived at by adjusting actual 2007 expenses.

In response, PGE acknowledges that, in a data request to Staff, it had mistakenly reported that it would trim 4,500 line miles, and later corrected that response to reflect the accurate estimate of 4,112 miles.[59] PGE contends, however, that the error did not affect its original $12.3 million request, which was based on the estimated equipment and crews needed to meet its tree trimming responsibilities. These responsibilities, PGE explains, include both the 4,112 miles of scheduled trimming, as well as other required vegetation maintenance services.

Resolution

Although PGE has clarified that its request for recovery of $12.3 million is not affected by the erroneous data response, it has not explained why, given the comparable number of line miles trimmed in 2007, costs would increase by 13.7 percent at a time when costs-per-mile are declining. We adopt Staff's calculations and make a downward adjustment in the 2009 revenue requirement of $1.397 million.

b. Porcelain Insulator Replacement Costs

PGE has undertaken a project to replace all of its porcelain insulators. The amount spent on the project fluctuates from year to year. In 2006, PGE spent $791,894; in 2007 it spent $525,789. In its application, PGE seeks recovery of $684,000 for the 2009 test year.

Staff recommends a $287,000 disallowance based on escalated contractor and other non-labor expenses. Staff explains that program expenses for the project totaled $525,789 in 2007, of which $144,158 was attributable to PGE labor expense, and the remaining $381,631 was attributable to contract labor and non-labor expenses. Because PGE plans to only use contractors during the 2009 test year, Staff escalated only the 2007 contract labor and non-labor costs ($381,631) in arriving at its forecasted 2009 test-year expense. Staff views this approach as maintaining the status quo, as adjusted for inflation. Staff explains that it did not escalate the PGE labor expense because if PGE chooses to hire contractors, as opposed to using PGE labor, it should fund such a decision with the cost savings associated with a reduced PGE labor expense.[60]

In response, PGE contends that it expects to use its own labor force in addition to hiring contract labor. Thus, contrary to Staff's assertion, PGE states that it will not actually have lower labor expenses. PGE explains that, regardless of who performs the work, PGE will incur project expenses, and that Staff's significant disallowance will result in insufficient workers to complete the scheduled work.

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[59] PGE/2500, Hawke/6-7; PGE/2501.
[60] Staff/900, Ball/17.

Resolution

We agree with Staff that it is reasonable to maintain funding at present levels adjusted for inflation. We therefore conclude that PGE should expect to realize greater savings with respect to its proposed 2009 revenue requirement for the Porcelain Insulator Replacement project. We adopt Staff's analysis and reduce PGE's revenue requirement by $298,000.

c. Locating Costs

PGE seeks an increase of $700,000 in costs to locate its underground facilities for construction and other required purposes. PGE explains that 95 percent of the increase is due to higher contract rates, and the remaining 5 percent is due to a greater number of forecasted locates.

Staff challenges only PGE's contract costs. Based on information provided by PGE, Staff claims that the Company "submitted a test-year increase in contract locating costs of approximately $480,000, not $688,548."[61] As a consequence, Staff contends PGE's request is overstated and should be reduced by approximately $271,000.

PGE contends that Staff's proposed adjustment is based on incorrect assumptions. PGE explains that Staff's analysis focuses only on non-labor (contract costs) and does not consider labor costs. PGE states that its locating expenses have a portion of PGE labor "because there are areas in our service territory that necessitate a high level of expertise to accurately locate our facilities and these locates cannot be performed by contract labor." PGE asserts that including PGE's labor costs would result in a $60,000 adjustment, rather than the $271,000 recommended by Staff. [62]

Resolution

In support of its request for increased locating expense, PGE clarified that 95 percent of the increase was due to higher contracting costs. Based on that assertion, and its later data request response to Staff indicating that its contract loading costs had increased by $488,000, we find that PGE has failed to support the substantial proposed increase in *contract* costs questioned by Staff. We adopt Staff's recommendation and reduce the proposed revenue requirement for contract locating expense by $281,000.

[61] Staff/900, Ball/17, citing PGE/16, Hawke/13.
[62] PGE attributes the increase in the number of locates to three factors: the increasing percentage of underground service, state road construction, and Verizon's multi-year fiber optic installation project. PGE/600, Hawke/14; PGE/2500, Hawke/3-5. *See also* PGE Reply Brief at 20-21.

d. Arc Flash Mitigation

PGE accepts Staff's proposed reduction of $281,000 in revenue requirement for Arc Flash Mitigation.[63] We therefore adopt Staff's proposed reduction.

e. Underground FITNES Program

The FITNES program inspects, maintains, and repairs all of PGE's 280,000 poles on a ten-year cycle, and all of the underground equipment on a four-year cycle, including PGE equipment located on industrial campuses. The program lowers replacement costs and outages with preventive maintenance. The most recent cycle was completed early in 2007. Due to overall efficiencies in the preceding two-year period, PGE's 2007 costs were unusually low and therefore inconsistent with its proposed test-year expense.[64]

In its filing, PGE offered to reduce its 2009 revenue requirement, dependant on moving the underground FITNES program from a four-year to a 10-year cycle, thus decreasing costs by 60 percent or $900,000.[65] Staff opposes cost reduction in this way, asserting that changes in the frequency of the service quality measure would be more appropriately handled through a separate proceeding outside of this docket. Staff proposes to set the 2009 funding for the project at the average cost per year for the past four-year cycle, adjusted for inflation.[66]

Resolution

We will not modify the underground FITNES program from a four-year to a ten-year cycle without a thorough review with all interested parties and our safety Staff in a separate proceeding. We adopt Staff's proposal and reduce PGE's revenue requirement by $323,000.

f. Other Benefits

The adjustments at issue refer to the following other employee benefits included in PGE's test-year expenses: Occupational Health Benefits; Ergonomics and Integrated Absence Management (IAM); Occupational Fitness; Recreation Program; Health Club Partial Reimbursement; Commuter Program; Service Awards; Retiree Association and Retiree Luncheon; Executive Financial Planning; and other unidentified expenses. Of these items, PGE has agreed to remove Executive Financial Planning from its revenue requirement, and Staff has withdrawn its proposed adjustment to the Commuter Program.

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[63] PGE Opening Brief at 21.
[64] PGE/600, Hawke/13-14.
[65] PGE/2500, Hawke/9.
[66] Staff Opening Brief at 13.

Staff supports Occupational Health Benefits, but disagrees with PGE's proposed increase in funding for the program. Although participation has increased 46 percent between 2006 and 2008, Staff notes that actual program costs have only increased about 1.7 percent. Staff proposes to allow $224,434 in funding for Occupational Health Benefits for 2009, which is an increase of approximately 19 percent over two years.[67] With respect to the IAM program, designed to reduce employee absences, Staff asserts that PGE has failed to link the program to cost reductions benefitting customers, and therefore costs associated with the program should be disallowed.[68] Staff supports Occupational Fitness, but believes that PGE's requested level of funding is unsupported by the record, which shows a recent decrease in costs.[69] Staff also proposes to remove the Recreation Program from the revenue requirement, as these activities are discretionary, take place outside the workplace, and are not required to provide safe and adequate service to customers.[70] Staff supports the Health Club Partial Reimbursement program, but questions whether increasing classes and activities will almost double program costs as indicated by PGE. Instead, Staff supports allowing a 20 percent increase resulting from increased participation for the test year.[71] Staff proposes to adjust the proposed expense for Service Awards in a manner similar to the adjustment for merit-based bonuses—50 percent to customers and 50 percent to shareholders. Finally, Staff recommends disallowance of expenses for Retiree Association and Retiree Luncheon because they are not required to provide safe and adequate service to customers, and to disallow all other unidentified, and therefore unjustified, expenses.[72]

In response, PGE claims that these benefits represent a comparatively small amount of overall benefits yet are a critical part of an overall package designed to attract and retain qualified employees.

Resolution

We concur with Staff's analysis and adopt the calculations contained in Staff/900, Ball/10, to adjust PGE's 2009 revenue requirement through the disallowance of $319,000.

g. Insurance

Staff proposes several adjustments to PGE's requested test-period, insurance-related expense. First, Staff cites falling premiums in the current soft market and recommends no escalation for property and liability premiums.[73] Second, Staff proposes to eliminate 50 percent of the excess Directors' and Officers' (D&O) insurance

[67] Staff/900, Ball/5-6.
[68] *Id. at* 6-7.
[69] *Id.* at 7.
[70] *Id.* at 8.
[71] *Id.*
[72] *Id.* at 9.
[73] Staff/300, Ball-Dougherty/9; Staff/901, Ball/3.

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

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

Resolution

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

h. Miscellaneous Expenses

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

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

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

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

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

Resolution

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

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

i. Senate Bill 408 Ratio Adjustment

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

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

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

in docket UM 1271.[83] There, PGE had sought a deferral to prevent customers from receiving any tax benefit associated with a non-regulated activity. Staff contends PGE now seeks to similarly shield customers from tax benefits, and concludes that the proposal is inconsistent with previous Commission decisions.[84]

In response, PGE asserts that nothing in SB 408 or the implementing rules prevents the Commission from establishing the "net to gross" revenue ratio in a manner that recognizes the expected profitability of the utility as a result of a general rate case. PGE states that the Commission has the authority and discretion to establish fair and reasonable ratios and should exercise that authority to account for the disallowed costs that PGE is contractually or likely to incur. PGE concludes that customers should not be permitted to share in a tax benefit if they are not responsible for paying the underlying expense.[85]

Resolution

We reject PGE's proposal. First, PGE's request is speculative, because it assumes that it will actually incur all the disallowed costs. Because its revenue-requirement request is based on forecasts and estimates, costs that have been disallowed—especially those found to be excessive—may not be realized. Second, even if the disallowed costs are realized, we cannot legally insulate shareholders from sharing tax benefits with ratepayers when costs are borne only by shareholders. In adopting rules implementing SB 408, and again in rejecting PGE's request to defer tax benefits associated with unregulated activities, we stated:

> Our authority to establish rates that include amounts for income tax expense has been specifically constrained by the Legislative Assembly. SB 408 expressly prohibits rates ultimately paid by customers to be based on the estimated taxes of the utility itself, without regard to unregulated activities or the operations of its parents and affiliates. Instead, the law requires that customers receive a share of tax savings realized when taxes are filed on a consolidated basis. Given the nature of the utility business, these tax savings are generally created when unregulated losses offset regulated revenues. While we have adopted rules to ensure that customers receive only the portion of those benefits properly attributed to regulated operations of the utility, SB 408 does not allow us to withhold all such realized benefits from ratepayers. [86]

[83] Order No. 07-421.
[84] Staff Opening Brief at 8-9 and cases cited therein.
[85] PGE Reply Brief at 29-30 and cases cited therein.
[86] Orders No. 06-400 at 12 and 07-421 at 7.

Thus, to the extent that PGE realizes tax benefits from costs that have been disallowed in this rate order, those benefits must, under SB 408, be reflected in rates paid by customers. Accordingly, we cannot consider the impact of disallowed costs in determining the tax rate and margin ratio for SB 408 purposes.

6. *Fixed Plant Costs (Issue S-11)*

During the 2009 test year, PGE will incur higher than normal maintenance costs for its Beaver, Boardman, and Colstrip generating plants. PGE and Staff disagree about the proper regulatory accounting mechanism to allow PGE to recover these additional costs, estimated to be approximately $6.8 million.[87]

PGE proposes to recover the net present value of the expense over time by creating a regulatory asset account and increasing the O&M test-year expenses by 20 percent. Under this proposal, PGE would recover the amount within five years and add $6.2 million to the rate base on which it would earn its authorized rate of return (ROR).

Staff does not support the creation of a regulatory asset and recommends that the balance be recovered over a ten-year period. Staff estimates that the additional costs expected for the 2009 test year will reoccur again approximately once every ten years.[88] PGE responds that it is willing to support a ten-year recovery period with adjustments to account for the time value of money.[89]

Resolution

We reject PGE's initial proposal to spread costs over the shorter five-year period and instead adopt the Company's alternative proposal to allow cost recovery through the creation of a ten-year "regulatory asset" with recovery of the time value of money. PGE's projected 2009 revenue requirement is therefore reduced by $5.62 million.

7. Property Tax Adjustment (Issue S-14)

PGE initially submitted a 2009 budget including $36.929 million for Oregon and Montana property taxes, but reduced that amount to $35.951 after a review of 2007 tax expense as a function of the 2007 rate base. PGE then proposed that property taxes should be considered a function of assets and tax rates and calculated accordingly, rather than escalating actual 2007 taxes by the CPI.[90]

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[87] PGE/400, Quennoz-Lobdell/9-11; PGE/1800, Quennoz/16.
[88] Staff Opening Brief at 17, citing Staff/1000, Durrenberger/6.
[89] PGE Reply Brief at 23-24.
[90] PGE/2300, Tooman-Tinker/20.

Staff argues that PGE's original methodology, which PGE had said "provides the derivation of a reasonable level of 2009 property tax expense that is aligned with 2007 actuals," should be retained, but that a correction should be made to address a mismatch in the method related to the Port Westward rate base amount.[91]

PGE acknowledges that Staff's proposal using the original methodology is reasonable, but that the resulting number will fail to recover the estimated 2009 tax expense.[92] PGE says that Staff errs in its analysis by suggesting that property taxes are a function of plant-in-service, net of depreciation, rather than a function of the overall rate base. PGE also believes that Staff relies on the unreasonable assumption that tax rates and assessed value due to capital additions will not increase.[93]

Resolution

PGE's original calculations were admittedly incorrect, and Staff properly applied PGE's methodology. PGE then proposed the adoption of a new expense forecasting method without adequate foundation. We find that Staff's approach is fully supported and concur in its recommendation. PGE's request for property tax expenses to be recovered through rates is rejected. PGE's 2009 projected revenue requirement is reduced by $2.991 million.

8. Generation Excellence (Issue CUB-1)

Generation Excellence is a program focused on the continued training of skilled personnel for PGE's generation facilities. CUB asserts that there is no analytic basis to allow recovery of the entire Generation Excellence program. CUB asserts that PGE failed to support its request with modeling that demonstrated the program's value. CUB further notes that the program would require additional staff for an operation that has already been found to be overstaffed.

Resolution

Like the Boardman simulator discussed below, Generation Excellence is a program that is essentially used to train plant personnel. We support the program because it is central to PGE's mission and to the reliability of its system. PGE's request to include related costs in revenue requirement is approved.

9. Boardman Simulator (Issue CUB-2)

The Boardman simulator provides on-site training to plant operators. PGE seeks recovery of the simulator costs on the basis that it benefits customers by improving safety and reliability in the operation of its generating facilities. CUB criticizes PGE's

[91] Staff Opening Brief at 18, citing PGE/1400, Tooman-Tinker/24 and Staff/900, Ball/26.
[92] PGE/2300, Tooman-Tinker/21.
[93] PGE Reply Brief at 28-29.

development of the simulator, citing cost overruns that eliminated the savings expected from an on-site training facility. CUB recommends the Commission disallow $1 million of simulator costs.

In reply, PGE asserts that the primary benefit of the simulator has always been reliability, not cost savings. PGE contends recovery of all costs should be allowed because the simulator is a training tool designed to improve safety, reduce outages, and lower costs over the long term.[94]

Resolution

The Boardman simulator provides training central to PGE's mission and to system reliability. We find the Boardman simulator, and the costs that have been associated with its acquisition and operations, to be reasonable and allow them to be recovered in rates.

10. Customer Focus Initiative (Issue CUB-3)

The Customer Focus Initiative is designed to train employees to improve customer service and efficiency. CUB objects to the Customer Focus Initiative, which it asserts is not focused on controlling rates charged to customers, but is rather an attempt to build a new corporate culture "filled with corporate buzz words which attempt to motivate employees, but without any core focus."[95] CUB also contends that, despite its name, the program "provides little or no benefit to employees, customers, or shareholders."[96]

Resolution

We agree with CUB and find that PGE has failed to establish the reasonableness of recovery of costs associated with the Customer Focus Initiative. We reduce PGE's revenue requirement by $311,000.

11. Helicopter Costs (Issue CUB-4)

In its initial filing, PGE sought recovery of $200,000 in capital costs for a new helicopter. PGE later removed these costs from the 2009 test year but seeks an increase in existing helicopter expense. CUB contends that PGE has overestimated its expected existing helicopter expense. CUB claims that PGE's forecast of 250 hours of use is unlikely, given that the helicopter was used only 154 hours in 2006 and 154 hours in 2007. CUB proposes an adjustment assuming 175 flight hours, thus reducing fuel expenses by $26,000.[97]

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[94] PGE Reply Brief at 23.
[95] *Id.* at 31-34 and testimony cited therein.
[96] *Id*.
[97] CUB Opening Brief at 36-37.

Resolution

We acknowledge PGE's delay in putting a new helicopter into service until after the 2009 test year and therefore remove $200,000 from the 2009 revenue requirement. We decline to make any further adjustment to PGE's helicopter expense and reject CUB's proposal.

12. PGE Decoupling Proposal

PGE currently recovers most of its fixed costs through rates charged on a per-kilowatt-hour (kWh) basis. PGE asserts that reduced energy sales from efficiency and conservation result in reduced fixed cost recovery and earnings and therefore that there is a disincentive for the Company to promote demand-side management programs. PGE proposes a fixed cost-recovery, true-up mechanism, to be implemented in Schedule 123, consisting of a Sales Normalization Adjustment (SNA) balancing account applied to residential (Schedule 7) and small non-residential (Schedules 32 and 532) customers, as well as a Lost Revenue Recovery (LRR) mechanism applied to large non-residential customers with loads less than 1 average megawatt (MWa). As an alternative to the LRR, PGE proposes a "load-based" decoupling mechanism. Very large non-residential customers are not part of the proposal.[98]

In essence, the SNA would compare actual weather-adjusted distribution, transmission, and fixed generation revenues that are collected on a per-kWh basis with those that would be collected with a fixed per-customer charge. The difference is accumulated in a balancing account and refunded or collected over a future period. PGE would receive revenues as if it had a flat distribution charge while customers would continue to be billed on a per-kWh basis.[99]

Staff opposes PGE's proposals for several reasons. Staff contends that PGE will most likely over-collect its fixed costs with the SNA and asserts that the SNA mechanism shifts risk historically borne by shareholders to ratepayers.[100] Furthermore, since PGE states that it anticipates "frequent rate filings," Staff believes that any potential inequity to shareholders without an SNA will be limited. Staff also does not believe that removal of the disincentive for efficiency will change PGE's behavior because the Energy Trust of Oregon (ETO) already serves the function of encouraging efficiency and conservation separate from utilities. Staff also contends that the proposal does not appear to support the objective to encourage customer efficiency because the SNA would create a disincentive for customers to undertake improvements in energy efficiency by increasing rates and reducing bill savings.

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[98] PGE/100, Piro/17-18.
[99] PGE/1200, Kuns-Cody/28-30.
[100] Staff Opening Brief at 28-29 and testimony cited therein. *See also* Staff/1300, Storm/22-23.

CUB acknowledges that it has supported decoupling in prior utility rate cases to help remove any disincentives to pursue energy efficiency. Based on experience gained over the past decade, however, CUB is reconsidering its support.[101] Furthermore, CUB contends that "one significant risk that is removed from the utility and placed onto customers is the risk of a recession[.] With decoupling in place during an economic downturn, however, a surcharge would be added to customers' bills to ensure that utilities earned the same profit they would have earned if loads hadn't declined."[102]

Kroger objects to the decoupling proposal on a fundamental level, because it is as much a "revenue assurance" mechanism as it is a "conservation enabling mechanism," providing unwarranted insulation from price elasticity faced by other businesses. Kroger compares decoupling to single-issue ratemaking, which it claims is not sound regulatory practice.[103] Furthermore, Kroger adds, the argument for decoupling is especially weak in Oregon because the independent, non-utility ETO administers energy conservation programs for PGE and other utilities. Finally, Kroger argues that if a decoupling mechanism is adopted, the fixed generation cost component should not be applied to direct access service.[104]

In reply, PGE states that the Commission has an opportunity to correct the current misalignment of utility and customer interests in energy efficiency, and the contradictions inherent in the current system should not be ignored. PGE contends that its proposal ensures that risks and rewards are balanced and believes that Staff ignores the plan's benefits and has failed to explain why the proposal's outcomes are improper.[105]

Resolution

The parties opposing PGE's SNA proposal raise three basic arguments which we address in turn.

First, while the parties do not disagree that relying on volumetric charges to recover fixed costs creates a disincentive to promote energy efficiency, they contend that decoupling is unnecessary because, with the ETO running energy efficiency programs in PGE's service territory, the Company has limited influence over customers' energy efficiency decisions. We find this position unpersuasive, because PGE does have the ability to influence individual customers through direct contacts and referrals to the ETO. PGE is also able to affect usage in other ways, including how aggressively it pursues distributed generation and on-site solar installations; whether its supports improvements to building codes; or whether it provides timely, useful information to customers on energy efficiency programs. We expect energy efficiency and on-site power generation will have an increasing role in meeting energy needs, underscoring the need for appropriate incentives for PGE.

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[101] CUB Opening Brief at 48.
[102] *Id.* at 48-49, citing CUB/100, Jenks/46.
[103] Kroger Opening Brief at 2.
[104] *Id.* at 2-3.
[105] PGE Reply Brief at 34-35.

Staff also argues that the SNA would create a disincentive for customers to improve their energy efficiency because the SNA would increase rates and reduce the bill savings. We believe that the opposite is true: an individual customer's action to reduce usage will have no perceptible effect on the decoupling adjustment, and the prospect of a higher rate because of actions by others may actually provide *more* incentive for an individual customer to become more energy efficient.

The second argument against PGE's proposal is that there are alternative means to deal with margin losses due to energy efficiency and conservation; *e.g.*, by filing more frequent rate cases or including expected savings in load forecasts. Even with frequent rate cases, however, PGE would still lose the margins from energy conservation activities until rates could be reset, and the load forecast in a rate case does not include any savings beyond the test year. Even for savings recognized in the load forecast, the disincentive for energy efficiency remains because, once rates are set, the Company loses margin if those savings actually occur.

The final overall argument is that the SNA shifts risk to customers and allows PGE to recover more than its fixed costs. Although PGE argues that there is no *shift* in risk from the Company to its customers, there is general agreement that PGE's risk will go down, raising the question as to whether the Company's authorized ROE should be reduced to reflect the risk reduction. We also agree that, under the SNA, PGE may be able to recover more than its fixed cost if customer growth exceeds what was assumed in setting rates (assuming those costs really are fixed and do not increase with the customer count). We have taken these benefits to PGE into account in conditioning our decoupling proposal below on a ten-basis point reduction in the Company's authorized ROE.

Because we conclude that PGE does have the ability to influence customer usage, we believe that a properly constructed decoupling mechanism would promote behavior by the Company that would be publicly beneficial. Accordingly, PGE may refile tariffs to implement its proposed SNA and LRR[106] with the following modifications and conditions:

a. The fixed cost-recovery factors should be conformed to the revenue-requirement decisions in this order.

b. The interest rate to be applied to monthly SNA and LRR balances shall be the Blended Treasury Rate applied to amortized deferred accounts, rather than the authorized ROR as proposed by PGE, because recovery is more certain than for unamortized deferred accounts; *e.g.*, no prudence review is required.

[106] We understand Mr. Cavanagh's concerns about using an LRR-type mechanism that tracks savings instead of a load-based mechanism (PGE/2100, Cavanagh/13-14), but we think it is reasonable to test a different mechanism for large business customers during the two-year trial.

c. PGE's authorized ROE shall be reduced by ten (10) basis points to reflect the reduction in the Company's risk. The Company should file an application to defer the revenue-requirement effect of this change until it can be reflected in base rates.

d. Kroger's recommendation that the fixed generation cost component of an SNA or LRR adjustment not be applied to direct access customers is not adopted. The volumetric rates charged to direct access customers include fixed generation costs, and we see no reason that those customers should not be subject to the same adjustment for variations in fixed cost recovery as other non-residential customers.

e. The SNA and LRR will terminate two years after the effective date of the approved tariffs. PGE may request an extension of the mechanism or a revised mechanism no later than three months before the scheduled expiration of the tariffs. To allow a full review of PGE's costs, the Commission may condition extension of the existing, or a modified, mechanism on the filing of a general rate case.

f. No later than six months before the scheduled expiration date, PGE shall submit an assessment of the effectiveness of the SNA and LRR mechanisms. Issues to be addressed include but are not limited to the following:

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

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

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

- 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.

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

- 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 this proceeding?

g. During the two-year period outlined above, parties are encouraged to convene to evaluate and recommend revisions in the mechanisms. PGE should also seek, in conjunction with other parties, to identify any other needed assessment issues for the effectiveness study. Parties retain the right to intervene in any proceeding regarding PGE's decoupling tariffs in order to oppose or comment upon the extension or modification of any decoupling mechanism.

PGE shall file a revised Schedule 123 and deferred accounting application consistent with the terms of this order, or notify the Commission of its decision not to file such a decoupling tariff, no later than 15 days from the date of this order.

IV. CONCLUSION

We reaffirm and readopt our findings and conclusions made in Order Nos. 08-585 and 08-601. Based on those determinations, as well as on those made on the stipulated and contested issues in this order, we authorize PGE to increase its revenues for non-NVPC-related costs by $25.6 million. We find this increase will provide adequate revenue for the utility's operating expenses and capital costs, with a return to PGE's shareholders that is commensurate with the return on investments in similar enterprises and sufficient to maintain confidence in the financial integrity of the utility. Accordingly, we conclude the rates are just and reasonable.

Combined with our earlier decision approving a stipulation resolving NVPC issues, this order results in an overall increase in revenues of approximately $121.0 million, or 7.6 percent, effective January 1, 2009. The net rate increase, including the effect of all previously approved changes to supplemental rate schedules, is 5.6 percent overall for cost of service customers. The average increase for residential customers is 5.9 percent.[107]

The net effect of the resolution of issues in this order is summarized in the following table:

[107] *See* PGE Advice No. 08-23.

PORTLAND GENERAL ELECTRIC
ISSUE SUMMARY
Twelve Months Ended December 31, 2009
($000)

Item	Issue	Revenue Requirement Effect
	PGE PROPOSED REVENUE REQUIREMENT INCREASE (Adjusted by Errata Filing) [UE 197: $93.6 million non-NVPC. UE 198: $53.0 million NVPC]	$146,630
	Adopted Commission adjustments (* indicates stipulated adjustments)	
S-0*	Rate of Return	(12,906)
S-1*	Other Electric Revenues	470
S-2*	Research and Development	(675)
S-3 & ICNU/CUB-1	Workforce / Wage & Salary Adjustment	(15,811)
S-4	Corp Incentives	(8,070)
ICNU/CUB-2	Employee Discount	0
S-5*	Cap Ex	(11,020)
S-6*	Lease Adjustment	0
S-7*	Fuel Adjustment	0
S-8*	Membership Adjustment	0
S-9	A&G and O&M	(8,481)
S-10*	WECC Reliability Center, Regional Trans Planning & flow mitigation	(155)
S-11	Fixed Plant Costs	(5,620)
S-12*	Kelso Beaver Pipeline Transmission	(1,036)
S-13*	NERC/WECC Consultant, RCM Program costs, Misc Unspecified software upgrades	(207)
S-14	Property Tax Adjustment	(2,991)
S-15*	NVPC Adjustment (UE 198)	42,387
S-16*	Revenue Sensitive Costs	(823)
S-17*	Schedule 300	0
S-18*	Port Westward and Biglow Canyon	(113)
S-19*	Energy Audits	(152)
CUB-1	Generation Excellence	0
CUB-2	Boardman Simulator	0
CUB-3	Customer Focus Initiative	(311)
CUB-4	Helicopter	(200)
	Rounding	59
	Total Adjustments (Base Rates):	(25,655)
	Revenue Requirements Change (Base Rates):	$120,975

ORDER

IT IS ORDERED that:

1. The First and Second Stipulations attached as Appendix A are adopted.

2. The Portland General Electric Company 2009 test-year revenue requirement is adjusted to the extent set forth in Appendix B to this order.

3. The tariffs in Advice No. 08-02 are permanently suspended.

4. Portland General Electric Company must file tariffs consistent with this order no later than December 31, 2008.

5. Our decision in Order No. 08-585 adopting the Third Stipulation regarding Rate Spread and Rate Design Issues is reaffirmed.

6. A new docket will be opened to address issues of cost allocation, rate spread, and rate design for Portland General Electric Company.

7. PGE must file a revised Schedule 123 and deferred accounting application consistent with the terms of this order, or notify the Commission of its decision not to file such a decoupling tariff, no later than 15 days from the date of this order.

Made, entered, and effective JAN 2 2 2009.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 197

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a general rate revision	)))))))	**STIPULATION REGARDING REVENUE REQUIREMENT ISSUES**

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

I. INTRODUCTION

On February 27, 2008, PGE filed this general rate case. On March 21, 2008, a prehearing conference was held in Docket No. UE 197. At that prehearing conference, the Docket was bifurcated, and Docket No. UE 198 was initiated to address all issues regarding PGE's net variable power costs ("NVPC"). Re PGE, Docket Nos. UE 197/198, Joint Prehearing Conference Report at 2 (Mar. 24, 2008). All other issues remained in this Docket. A procedural schedule was adopted for this Docket at that time. On March 31, 2008, the Commission suspended the filed tariff sheets for a period not to exceed nine months from the proposed effective date of the tariffs, April 1, 2008, making revised rates pursuant to this general rate case effective January 1, 2009.

PGE has responded to numerous data requests in this Docket from Staff and intervenors.

PGE has also held several workshops. Settlement conferences, open to all parties, were held in this Docket on June 12, 2008, and June 19, 2008. As a result of those settlement discussions, the Stipulating Parties have agreed to certain adjustments to PGE's requested revenue requirement in this Docket. The Stipulating Parties submit this Stipulation to the Commission and request that the Commission adopt orders in this Docket implementing the following.

II. TERMS OF STIPULATION

1. This Stipulation is entered to settle only the issues described below. Other issues may be raised by the Stipulating Parties in their testimony.

2. The Stipulating Parties agree that PGE will reduce its revenue requirement request by approximately $13.6 million, including appropriate rate base modifications, to reflect the following agreements and adjustments:

a) S-0, Rate of Return. The Stipulating Parties agree that PGE's authorized return on equity should be 10.1%, the same as currently authorized. PGE's capital structure for ratemaking purposes should also remain unchanged at 50% equity and 50% debt. PGE's cost of debt should be 6.567% as set forth in PGE's initial filing in this Docket. These changes result in a revenue requirement decrease of approximately $12.9 million.

b) S-1, Other Electric Revenues. PGE's forecast of other revenues should be decreased by $455,000, as a result of the change in proposed Schedule 300 prices described in Section II(2)(g) as well as changes to additional other revenue items.

c) S-6, Lease Adjustment. Staff proposed a lease expense adjustment related to PGE's lease of the Tualatin Call Center building. As part of this settlement, the Stipulating Parties agree that no lease adjustment should be made.

d) S-7, Fuel Adjustment. Staff proposed an adjustment to PGE's forecast of materials and fuel inventories in rate base. As part of this settlement, the Stipulating Parties agree that no such adjustment should be made.

e) S-8, Membership Adjustment. Staff proposed an adjustment to PGE's forecast of Western Electricity Coordinating Council membership costs. As part of this settlement, the Stipulating Parties agree that no such adjustment should be made.

f) S-12, Kelso-Beaver Pipeline. The Stipulating parties agree that forecasted O&M expenses associated with the Kelso-Beaver pipeline should be reduced by $1.0 million.

g) S-17, Schedule 300. PGE's proposed increases to Schedule 300 prices should not be adopted. Schedule 300 prices should remain as they are in PGE's current tariff. As a part of this settlement, the Stipulating Parties agree that the adjustment to remove revenues associated with PGE's original proposal for Schedule 300 is reflected in the adjustment for Other Revenues (S-1 above).

h) S-18, Rate base True-ups. The Stipulating Parties agree that rate base amounts for Biglow Canyon Phase 1 and Port Westward for the end of 2007 and beginning of 2008 used in forecasts in this Docket should be trued-up to actual 2007 year-end net investment balances. As a result, the Stipulating Parties agree that PGE's forecast of average 2009 rate base should be reduced by $735,000 and its estimate of 2009 book depreciation expense should be reduced by $24,000. This will result in a revenue requirement decrease of about $113,000.

3. The estimated impact of all of these changes is a reduction in revenue requirement in this Docket of approximately $13.6 million. However, the final impact on revenue requirement is unknown as it is dependent, in part, on revenue sensitive factors that are not included in this stipulation.

4. The Stipulating Parties recommend and request that the Commission approve the adjustments described above as appropriate and reasonable resolutions of these issues.

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

6. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the parties. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding.

7. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that is inconsistent with the terms of this Stipulation, the Stipulating Parties reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

8. 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 Party

reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation or adds such material condition. 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.

9. 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 the explanatory brief or written testimony required by OAR § 860-14-0085(4).

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

11. 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 4th day of August, 2008.

/s/: Douglas C. Tingey
PORTLAND GENERAL ELECTRIC COMPANY

/s/: Jason Jones
STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

/s/: Bob Jenks
CITIZENS' UTILITY BOARD OF OREGON

/s/: S. Bradley Van Cleve
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

/s/: Kip Phiel
OREGON DEPARTMENT OF ENERGY

/s/: Kurt J. Boehm
FRED MEYER STORES AND QUALITY FOOD CENTERS DIVISIONS OF KROGER CO.

PORTLAND GENERAL ELECTRIC
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OREGON DEPARTMENT OF
ENERGY

K Boehm, Attorney for Kroger, Co.

FRED MEYER STORES AND
QUALITY FOOD CENTERS
DIVISIONS OF KROGER CO.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 197

In the Matter of	)	
	)	
PORTLAND GENERAL ELECTRIC COMPANY	)	**STIPULATION REGARDING CERTAIN REVENUE REQUIREMENT AND TARIFF ISSUES**
	)	
Request for a general rate revision	)	
	)	

This Stipulation ("Stipulation") is among Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon, and the Industrial Customers of Northwest Utilities (collectively, the "Stipulating Parties").

I. INTRODUCTION

On February 27, 2008, PGE filed this general rate case. Four rounds of testimony have been filed, with the final round scheduled to be filed by PGE on October 1, 2008. A Stipulation resolving certain revenue requirement issues, along with supporting testimony, was filed in this docket on August 5, 2008. A settlement conference, open to all parties, was held in this Docket on September 22, 2008. As a result of those settlement discussions, the Stipulating Parties have agreed to certain adjustments to PGE's requested revenue requirement in this Docket, and to a tariff change. The Stipulating Parties submit this Stipulation to the Commission and request that the Commission adopt orders in this Docket implementing the following.

II. TERMS OF STIPULATION

1. This Stipulation is entered to settle only the issues described below.

2. The Stipulating Parties agree that PGE's requested revenue requirement should be reduced by approximately $13.2 million, including appropriate rate base modifications, to reflect the following agreements and adjustments:

a) S-2, Research and Development. The Stipulating Parties agree that test year O&M expenses for research and development should be reduced by $650,000. This allows for a level of funding of approximately $350,000 on an annual basis. The approximate rounded revenue requirement effect of this adjustment is a reduction of $0.7 million.

b) S-5, Capital Additions. In its testimony Staff raised as issues certain capital additions included in the 2009 test year. Specifically Staff identified additions to the Boardman plant, Clackamas relicensing capital additions, and the Selective Water Withdrawal ("SWW") facility at Pelton-Round Butte. In its rebuttal testimony PGE revised its expected completion of the Clackamas relicensing from December 2009 to first quarter 2010, and accordingly removed it from the 2009 test year. As the Parties now agree with PGE's rebuttal position regarding the Clackamas relicensing, the combined adjustments to remove the SWW and the Clackamas relicensing are as follows:

1) The $65.968 million of average rate base ($63.250 for the SWW project and $2.717 for Clackamas relicensing) will be removed from the request in this docket. Associated depreciation expense of $2.039 million (completely attributable to the SWW since the relicensing would not have had depreciation due to in-

service date of December 30, 2009) and property tax expense of $1.049 million ($1.006 million for SWW project and $0.43 million for Clackamas relicensing) will also be removed.

2) The inclusion in rates of the SWW project capital additions and related expenses including depreciation and property tax expense, will be the subject of a separate docket to be initiated on or before October 31, 2008. The inclusion of the SWW project capital additions and related expenses will be the only issues in this separate docket. The Stipulating Parties agree to propose a schedule and to make a good-faith effort to complete the SWW docket that will allow for a Commission decision such that rates that include recovery of approved costs from the SWW docket may be effective the later of May 1, 2009, or when the SWW project is closed to plant for accounting purposes. The Stipulating Parties further agree to work together in good faith throughout the SWW docket to maintain the schedule.

The rounded revenue requirement impact of these changes is a reduction of approximately $11.1 million. There will be no other adjustments to PGE's capital additions identified in Staff's issue S-5.

c) S-10, WECC Reliability Center and Regional Transmission Planning and Flow Mitigation. PGE's forecast of O&M expenses for the WECC reliability center and related regional transmission planning and flow mitigation should be decreased by $150,000. The rounded revenue requirement effect of this change is $0.2 million.

d) S-13, NERC/WECC Consultant, RCM Program Costs, Miscellaneous Software Upgrades. The Stipulating Parties agree that combined test year O & M expenses for a NERC/WECC consultant, RCM program costs, and miscellaneous software upgrades should be reduced by $200,000. The rounded revenue requirement effect of this change is $0.2 million.

e) S-16, Revenue Sensitive Costs. The Stipulating Parties agree that an uncollectibles rate of 0.43% should be used in this case. There should be no other changes to revenue sensitive costs as proposed by PGE. This change, at PGE's current requested revenue level, is a reduction of $867,000 and decreases revenue requirement by a rounded amount of approximately $0.9 million, though the final effect will not be determined until the Commission approves PGE's revenue requirement in this case.

f) S-19, Energy Audits. The Stipulating Parties agree that test year revenue requirement for customer accounting expense should be decreased by $150,000. PGE will reduce its test year O&M costs by $145,000, which will produce a revenue requirement reduction of $150,000.

g) Tariff Schedule 129. In its rebuttal testimony PGE proposed certain changes to Tariff Schedule 129, set out in PGE Exhibit/2001/Kuns-Cody-Lynn/4. The Stipulating Parties agree that the proposed changes to Tariff Schedule 129 should be adopted with the addition of an annual cap on the percent change in customer impacts for Schedules 83 and 89. A revised tariff sheet for Schedule 129 incorporating the agreed-upon changes is attached hereto as Exhibit "A", and the Stipulating Parties requests its adoption.

3. Attached Exhibit "B" demonstrates the amount of each adjustment and the impact of the revenue requirement associated with this Stipulated agreement. The estimated impact of all of these changes is a reduction in revenue requirement in this Docket of approximately $13.2 million. However, the final impact on revenue requirement is unknown as it is dependent, in part, on the total revenues authorized by the Commission in this proceeding. For the items identified above, the Stipulating Parties agree that this Stipulation fully resolves the issues addressed and that the Stipulating Parties will support the inclusion in PGE's revenue requirement of such expenses as adjusted pursuant to the terms of this Stipulation.

4. The Stipulating Parties recommend and request that the Commission approve the adjustments described above as appropriate and reasonable resolutions of these issues.

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

6. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the parties. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding.

7. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that is inconsistent with the terms of this Stipulation, the Stipulating Parties reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this

reservation of rights, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

8. 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 Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation or adds such material condition. 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.

9. 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, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

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

11. 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 day of October, 2008.

/s/ Douglas C. Tingey
PORTLAND GENERAL ELECTRIC
COMPANY

/s/ Jason W. Jones
STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

/s/ Robert S. Jenks
CITIZENS' UTILITY BOARD
OF OREGON

/s/ S. Bradley Van Cleve
INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

DATED this 7th day of October, 2008.

PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

CITIZENS' UTILITY BOARD
OF OREGON

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

DATED this day of October, 2008.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

DATED this 8th day of October, 2008.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

DATED this 7th day of October, 2008.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

S. Bradley Van Cleve

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected service under Schedule 483 and 489.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Period A (2002), the Transition Cost Adjustment will be:

0.061 ¢ per kWh	January 1, 2003 through December 31, 2007
0.000 ¢ per kWh	after December 31, 2007

For Enrollment Period B (2003), the Transition Cost Adjustment will be:

(0.154) ¢ per kWh	January 1, 2004 through December 31, 2004
(0.136) ¢ per kWh	January 1, 2005 through December 31, 2005
(0.062) ¢ per kWh	January 1, 2006 through December 31, 2006
(0.046) ¢ per kWh	January 1, 2007 through December 31, 2007
(0.032) ¢ per kWh	January 1, 2008 through December 31, 2008
0.000 ¢ per kWh	after December 31, 2008

For Enrollment Period C (2004), the Transition Cost Adjustment will be:

(0.763) ¢ per kWh	January 1, 2005 through December 31, 2005
(0.564) ¢ per kWh	January 1, 2006 through December 31, 2006
(0.447) ¢ per kWh	January 1, 2007 through December 31, 2007
(0.398) ¢ per kWh	January 1, 2008 through December 31, 2008
(0.301) ¢ per kWh	January 1, 2009 through December 31, 2009
0.000 ¢ per kWh	after December 31, 2009

For Enrollment Period D (2005), the Transition Cost Adjustment shall be:

(1.573) ¢ per kWh	January 1, 2006 through December 31, 2006
(1.359) ¢ per kWh	January 1, 2007 through December 31, 2007
(1.229) ¢ per kWh	January 1, 2008 through December 31, 2008
(0.998) ¢ per kWh	January 1, 2009 through December 31, 2009
(0.860) ¢ per kWh	January 1, 2010 through December 31, 2010
0.000 ¢ per kWh	after December 31, 2010

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

For Enrollment Period E (2006), the Transition Cost Adjustment will be:

(1.702) ¢ per kWh	January 1, 2007 through December 31, 2007
(1.483) ¢ per kWh	January 1, 2008 through December 31, 2008
(1.207) ¢ per kWh	January 1, 2009 through December 31, 2009
(0.997) ¢ per kWh	January 1, 2010 through December 31, 2010
(0.779) ¢ per kWh	January 1, 2011 through December 31, 2011
0.000 ¢ per kWh	after December 31, 2011

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

(1.250) ¢ per kWh	January 1, 2008 through December 31, 2008	(I)
(1.434) ¢ per kWh	January 1, 2009 through December 31, 2009	(R)
(1.248) ¢ per kWh	January 1, 2010 through December 31, 2010	
(1.145) ¢ per kWh	January 1, 2011 through December 31, 2011	
(0.949) ¢ per kWh	January 1, 2012 through December 31, 2012	(R)
0.000 ¢ per kWh	after December 31, 2012	

Three-Year Opt-Out Option

For Enrollment Period A (2002): Not available

For Enrollment Period B (2003): Not available

For Enrollment Period C (2004), the Transition Cost Adjustment will be:

(0.763) ¢ per kWh	January 1, 2005 through December 31, 2005
(0.564) ¢ per kWh	January 1, 2006 through December 31, 2006
(0.447) ¢ per kWh	January 1, 2007 through December 31, 2007

For Enrollment Period D (2005), the Transition Cost Adjustment will be:

(1.573) ¢ per kWh	January 1, 2006 through December 31, 2006
(1.359) ¢ per kWh	January 1, 2007 through December 31, 2007
(1.229) ¢ per kWh	January 1, 2008 through December 31, 2008

For Enrollment Period E (2006), the Transition Cost Adjustment will be:

(1.702) ¢ per kWh	January 1, 2007 through December 31, 2007
(1.483) ¢ per kWh	January 1, 2008 through December 31, 2008
(1.207) ¢ per kWh	January 1, 2009 through December 31, 2009

SCHEDULE 129 (Concluded)

TRANSITION COST ADJUSTMENT (Continued)
Three Year Opt-Out

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

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

SPECIAL CONDITIONS

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

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedule 483 and 489 customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges of the Large Nonresidential Rate Schedules 75, 76R, 83, 89, 483, 489, 575, 576R, 583, and 589. The changes in fixed generation revenues will be adjusted to account for a revenue sensitive cost factor of 1.0xxx. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage Charge resulting from changes in fixed generation revenues shall not result in a rate increase or decrease to Schedules 83 and 89 of more than 2 percent. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased Schedules 483 and 489 participating load will be determined.

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

Schedule		¢ per kWh
83	Secondary	x.xxx
	Primary	x.xxx
89	Secondary	x.xxx
	Primary	x.xxx
	Subtransmission	x.xxx

TERM

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

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Exhibit B
Stipulated Changes to Revenue Requirement

Issue	Total Operating Expense Change	Avg Rate Base Change	Approx. Rev Req Effect
S-2 R&D	$(650)k	$ ---	$(0.7) million
S-5 Cap Ex	$(3,088)k	$(65,968)k	$(11.1) million
S-10 WECC etc.	$(150)k	$ ---	$(0.2) million
S-13 NERC etc.	$(200)k	$ ---	$(0.2) million
S-16 Uncollectibles[1]	$(867)k	$ ---	$(0.9) million
S-19 Energy Audits	$(145)k	$ ---	$(0.15) million
Total Est. Impact			**$(13.2) million**

[1] The parties agree that a .43% uncollectible rate will be used in this case. The changes to O&M above are based on an estimated total revenue requirement in this case. The final impact of this change can only be determined once the Commission has issued its order on determining final revenue requirement in this case.

PORTLAND GENERAL ELECTRIC
UE 197/198
SUMMARY OF REVENUE REQUIREMENT
TWELVE MONTHS ENDED DECEMBER 31, 2009
(000)

	SUMMARY SHEET	2009 Results Per Company Adjusted Filing (1)	UE 197 Adjustments and UE 198 Final NVPC (2)	2009 Adjusted Results (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	**Operating Revenues**					
2	Retail Sales	$1,586,821	$922	$1,587,743	$120,975	$1,708,718
3	Wholesale Sales	0	0	0	0	$0
4	Other Revenues	19,346	(455)	18,891	0	$18,891
5	**Total Operating Revenues**	$1,606,167	$467	$1,606,634	$120,975	$1,727,609
6	**Operating Expenses**					
7	Net Variable Power Costs	$806,699	$41,742	$848,441	$0	$848,441
8	Production	108,251	(7,360)	100,891	0	100,891
9	Other Power Supply (Trojan)	129	0	129	0	129
10	Transmission	11,937	(150)	11,787	0	11,787
11	Distribution	68,198	(6,720)	61,478	0	61,478
12	Customer Accounting	65,235	(445)	64,790	0	64,790
13	OPUC Fees	4,959	3	4,962	378	5,340
14	Uncollectibles	7,617	(790)	6,827	520	7,347
15	Administrative and General	115,165	(22,761)	92,404	0	92,404
16	**Total Operation & Maintenance**	$1,188,190	$3,519	$1,191,709	$898	$1,192,607
17	Depreciation	$175,781	($2,328)	$173,453	$0	$173,453
18	Amortization	18,781	0	18,781	0	18,781
19	Taxes Other than Income	51,232	(5,451)	45,781	0	45,781
20	Income Taxes	16,648	2,648	19,296	44,858	64,154
21	Local taxes and Franchise Fees	39,893	23	39,916	3,041	42,957
22	**Total Operating Expenses**	$1,490,525	($1,589)	$1,488,936	$48,797	$1,537,733
23	**Net Operating Revenues**	$115,642	$2,056	$117,698	$72,178	$189,876
24	**Average Rate Base**					
25	Electric Plant in Service	$5,173,537	($73,460)	$5,100,077	$0	$5,100,077
26	Less: Accumulated Depreciation & Amortization	(2,674,938)	10	(2,674,928)	0	(2,674,928)
27	Accumulated Deferred Income Taxes	(286,862)	(20)	(286,882)	0	(286,882)
28	Accumulated Deferred Inv. Tax Credit	(271)	0	(271)	0	(271)
29	**Net Utility Plant**	$2,211,466	($73,470)	$2,137,996	$0	$2,137,996
30	Plant Held for Future Use	$0	$0	$0	$0	$0
31	Acquisition Adjustments	0	0	0	0	0
32	Working Capital	77,507	(83)	77,424	2,537	79,961
33	Fuel Stock	67,707	0	67,707	0	67,707
34	Materials & Supplies	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0
37	Prepayments	(37,755)	0	(37,755)	0	(37,755)
38	Misc. Deferred Debits	23,917	0	23,917	0	23,917
39	Misc. Rate Base Additions/(Deductions)	0	6,503	6,503	0	6,503
40	**Total Average Rate Base**	$2,342,842	($67,050)	$2,275,792	$2,537	$2,278,329
41	**Rate of Return**	4.94%		5.17%		**8.33%**
42	**Implied Return on Equity**	3.30%		3.78%		**10.10%**

PORTLAND GENERAL ELECTRIC
UE 197/198
INCOME TAX CALCULATION
TWELVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Income Tax Calculations	2009 Per Company Adjusted Filing (1)	Adjustments (2)	2009 Adjusted Results (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$1,606,167	$467	$1,606,634	$120,975	$1,727,609
2	Book Expenses Other than Depreciation	1,298,096	(1,909)	1,296,187	3,939	1,300,126
3	Depreciation	175,781	(2,328)	173,453	0	173,453
4	Interest	76,927	(2,202)	74,725	83	74,808
5	Less: Schedule M Differences	24,614	0	24,614	0	24,614
6	State Taxable Income	$30,749	$6,906	$37,655	$116,953	$154,608
7	Add OR Depletion Adjustment	$0	$0	$0	$0	$0
8	Total State Taxable Income	$30,749	$6,906	$37,655	$116,953	$154,608
9	State Income Tax	$1,574	$353	$1,927	$5,988	$7,915
10	State Tax Credits	(2,084)	0	(2,084)	0	(2,084)
11	Net State Income Tax	($510)	$353	($157)	$5,988	$5,831
12	Additional Tax Depreciation	0	0	0	0	0
13	Plus: Other Schedule M Differences	0	0	0	0	0
14	Federal Taxable Income	$31,259	$6,553	$37,812	$110,965	$148,777
15	Federal Tax @ 35%	10,941	2,295	13,236	38,870	52,106
16	Federal Tax Credits	0	0	0	0	0
17	Current Federal Tax	$10,941	$2,295	$13,236	$38,870	$52,106
18	ITC Adjustment		-			
19	Deferral	(8,363)	0	(8,363)	0	(8,363)
20	Restoration	1,456	0	1,456	0	1,456
21	Total ITC Adjustment	($9,819)	$0	($9,819)	$0	($9,819)
22	Provision for Deferred Taxes	$16,036	$0	$16,036	$0	$16,036
23	Total Income Tax	$16,648	$2,648	$19,296	$44,858	$64,154

APPENDIX B
PAGE 2 OF 7

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
SUMMARY OF ADJUSTMENTS
TWELVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Adjustments	Other Revenues (S-1)	Research & Develop Adj. (S-2)	Workforce & Wage Escal. (S-3) (ICNU/CUB-1)	Corporate Incentives (S-4)	Cap Ex (S-5)	Medical & Dental (S-9)	Other Benefits (S-9)	Tree Trimming (S-9)	Porcelain Ins. Replacement (S-9)	Locating Expense (S-9)	Arc Flash (S-9)
1	**Operating Revenues**											
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	(455)	0	0	0	0	0	0	0	0	0	0
5	**Total Operating Revenues**	**($455)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	**Operating Expenses**											
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production	0	0	0	0	0	0	0	0	0	0	0
9	Other Power Supply (Trojan)	0	0	0	0	0	0	0	0	0	0	0
10	Transmission	0	0	0	0	0	0	0	0	0	0	0
11	Distribution	0	0	0	(4,121)	0	0	0	(1,346)	(287)	(271)	(271)
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0
13	OPUC Fees	0	0	0	0	0	0	0	0	0	0	0
14	Uncollectibles	0	0	0	0	0	0	0	0	0	0	0
15	Administrative and General	0	(650)	(13,117)	(3,417)	0	(661)	(308)	0	0	0	0
16	**Total Operation & Maintenance**	**$0**	**($650)**	**($13,117)**	**($7,538)**	**$0**	**($661)**	**($308)**	**($1,346)**	**($287)**	**($271)**	**($271)**
17	Depreciation	0	0	(139)	(55)	(2,039)	0	0	0	0	0	0
18	Amortization	0	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	0	0	(1,518)	0	(1,049)	0	0	0	0	0	0
20	Income Taxes	(174)	249	5,720	2,934	2,015	254	118	516	110	104	104
21	Local Taxes and Franchise Fees	0	0	0	0	0	0	0	0	0	0	0
22	**Total Operating Expenses**	($174)	($401)	($9,054)	($4,659)	($1,073)	($407)	($190)	($830)	($177)	($167)	($167)
23	**Net Operating Revenues**	**($281)**	**$401**	**$9,054**	**$4,659**	**$1,073**	**$407**	**$190**	**$830**	**$177**	**$167**	**$167**
24	**Average Rate Base**											
25	Electric Plant in Service	0	0	(4,083)	(1,623)	(65,968)	0	0	0	0	0	0
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0	0
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	$0	$0	($4,083)	($1,623)	($65,968)	$0	$0	$0	$0	$0	$0
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0
32	Working Capital	(9)	(21)	(471)	(242)	(56)	(21)	(10)	(43)	(9)	(9)	(9)
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	0	0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0
40	**Total Average Rate Base**	**($9)**	**($21)**	**($4,554)**	**($1,865)**	**($66,024)**	**($21)**	**($10)**	**($43)**	**($9)**	**($9)**	**($9)**
41	**Revenue Requirement Effect**	**$470**	**($675)**	**($15,811)**	**($8,070)**	**($11,020)**	**($685)**	**($319)**	**($1,397)**	**($298)**	**($281)**	**($281)**

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
SUMMARY OF ADJUSTMENTS
TWELVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Adjustments	Underground FITNES Program (S-9)	Insurance (S-9)	Misc. Expenses (S-9)	WECC Rel, Reg Trans Plan Flow Mitigation (S-10)	Fixed Plant Costs (S-11)	Kelso-Beaver Pipeline Transmission (S-12)	WECC, RCM, Misc Soft & GP (S-13)	Property Taxes (S-14)	Final NVPC and Load Adj. (UE 198) (S-15)	Uncollectibles Expense (S-16)
1	**Operating Revenues**										
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$922	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	0	0	0	0	0	0	0	0	0	0
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$922**	**$0**
6	**Operating Expenses**										
7	Net Variable Power Costs	$0	$0	$0	$0	0	$0	$0	$0	$41,742	$0
8	Production	0	0	0	0	(6,160)	(1,000)	(200)	0	0	0
9	Other Power Supply (Trojan)	0	0	0	0	0	0	0	0	0	0
10	Transmission	0	0	0	(150)	0	0	0	0	0	0
11	Distribution	(312)	0	(112)	0	0	0	0	0	0	0
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0
13	OPUC Fees	0	0	0	0	0	0	0	0	3	0
14	Uncollectibles	0	0	0	0	0	0	0	0	4	(794)
15	Administrative and General	0	(3,583)	(1,025)	0	0	0	0	0	0	0
16	**Total Operation & Maintenance**	**($312)**	**($3,583)**	**($1,137)**	**($150)**	**($6,160)**	**($1,000)**	**($200)**	**$0**	**$41,749**	**($794)**
17	Depreciation	0	0	0	0	0	0	0	0	0	0
18	Amortization	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	0	0	0	0	0	0	0	(2,884)	0	0
20	Income Taxes	120	1,375	436	58	2,282	384	77	1,107	(15,674)	305
21	Local Taxes and Franchise Fees	0	0	0	0	0	0	0	0	23	0
22	**Total Operating Expenses**	($192)	($2,208)	($701)	($92)	($3,878)	($616)	($123)	($1,777)	$26,098	($489)
23	**Net Operating Revenues**	**$192**	**$2,208**	**$701**	**$92**	**$3,878**	**$616**	**$123**	**$1,777**	**($25,176)**	**$489**
24	**Average Rate Base**										
25	Electric Plant in Service	0	0	0	0	0	0	0	0	0	0
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0
32	Working Capital	(10)	(115)	(36)	(5)	(202)	(32)	(6)	(92)	1,357	(25)
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	6,503	0	0	0		0
40	**Total Average Rate Base**	**($10)**	**($115)**	**($36)**	**($5)**	**$6,301**	**($32)**	**($6)**	**($92)**	**$1,357**	**($25)**
41	**Revenue Requirement Effect**	**($323)**	**($3,717)**	**($1,180)**	**($155)**	**($5,620)**	**($1,036)**	**($207)**	**($2,991)**	**$42,387**	**($823)**

PORTLAND GENERAL ELECTRIC
UE 197/UE 198
SUMMARY OF ADJUSTMENTS
TWELVE MONTHS ENDED DECEMBER 31, 2009
(000)

	Adjustments	True-up of Port Westward Biglow Canyon (S-18)	Energy Audit Costs (S-19)	Generation Excellence (CUB-1)	Boardman Simulator (CUB-2)	Customer Focus Initiative (CUB-3)	Helicopter (CUB-4)	Total Adjustments (Base Rates)
1	**Operating Revenues**							
2	Retail Sales	$0	$0	$0	$0	$0	$0	$922
3	Wholesale Sales	0	0	0	0	0	0	$0
4	Other Revenues	0	0	0	0	0	0	($455)
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$467**
6	**Operating Expenses**							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$41,742
8	Production	0	0	0	0	0	0	($7,360)
9	Other Power Supply (Trojan)	0	0	0	0	0	0	$0
10	Transmission	0	0	0	0	0	0	($150)
11	Distribution	0	0	0	0	0	0	($6,720)
12	Customer Accounting	0	(145)	0	0	(300)	0	($445)
13	OPUC Fees	0	0	0	0	0	0	$3
14	Uncollectibles	0	0	0	0	0	0	($790)
15	Administrative and General	0	0	0	0	0	0	($22,761)
16	**Total Operation & Maintenance**	**$0**	**($145)**	**$0**	**$0**	**($300)**	**$0**	**$3,519**
17	Depreciation	(24)	0	0	0	0	(71)	($2,328)
18	Amortization	0	0	0	0	0	0	$0
19	Taxes Other than Income	0	0	0	0	0	0	($5,451)
20	Income Taxes	18	55	0	0	115	40	$2,648
21	Local Taxes and Franchise Fees	0	0	0	0	0	0	$23
22	**Total Operating Expenses**	($6)	($90)	$0	$0	($185)	($31)	($1,589)
23	**Net Operating Revenues**	**$6**	**$90**	**$0**	**$0**	**$185**	**$31**	**$2,056**
24	**Average Rate Base**							
25	Electric Plant in Service	(725)	0	0	0	0	(1,061)	($73,460)
26	Accumulated Depreciation & Amortization	10	0	0	0	0	0	$10
27	Accumulated Deferred Income Taxes	(20)	0	0	0	0	0	($20)
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	$0
29	**Net Utility Plant**	($735)	$0	$0	$0	$0	($1,061)	($73,470)
30	Plant Held for Future Use	0	0	0	0	0	0	$0
31	Acquisition Adjustments	0	0	0	0	0	0	$0
32	Working Capital	0	(5)	0	0	(10)	(2)	($83)
33	Fuel Stock	0	0	0	0	0	0	$0
34	Materials & Supplies	0	0	0	0	0	0	$0
35	Customer Advances for Construction	0	0	0	0	0	0	$0
36	Weatherization Loans	0	0	0	0	0	0	$0
37	Prepayments	0	0	0	0	0	0	$0
38	Misc. Deferred Debits	0	0	0	0	0	0	$0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	$6,503
40	**Total Average Rate Base**	**($735)**	**($5)**	**$0**	**$0**	**($10)**	**($1,063)**	**($67,050)**
41	**Revenue Requirement Effect**	**($113)**	**($152)**	**$0**	**$0**	**($311)**	**($200)**	**($12,808)**

PORTLAND GENERAL ELECTRIC
UE 197/198
COST OF CAPITAL
TWELVE MONTHS ENDED DECEMBER 31, 2009

COMMISSION AUTHORIZED

COST OF CAPITAL	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	50.00%	6.567%	3.284%
Preferred Stock	0.00%	0.000%	0.000%
Common Equity	50.00%	10.100%	5.050%
Total	100.00%		8.334%

PORTLAND GENERAL ELECTRIC
UE 197/198
REVENUE SENSITIVE COSTS
TWELVE MONTHS ENDED DECEMBER 31, 2009

REVENUE SENSITIVE COSTS	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00430
Taxes Other - Franchise	0.02514
OPUC Fees (separate line item on Model) - Resource supplier	0.00313
State Taxable Income	0.96744
State Income Tax @ 5.120%	0.04953
Federal Taxable Income	0.91791
Federal Income Tax @ 35%	0.32127
Total Taxes	0.37080
Total Revenue Sensitive Costs	0.40337
Utility Operating Income	0.59664
Net-to-Gross Factor	1.67607