PGE

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March 31, 2005

VPN-002-2005

Trojan ISFSI
Docket No. 72-017
License No. SNM-2509

ATTN: Document Control Desk
Director, Spent Fuel Project Office
Office of Nuclear Material Safety and Safeguards
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Sirs:

Submittal of Decommissioning Funding Information as Required by Nuclear Regulatory Commission Letter Approving Partial Exemption from 10 CFR 72.30(c)(5) (TAC No. L23737)

In response to Nuclear Regulatory Commission (NRC) letter "Partial Conditional Exemption From the Requirements of 10 CFR 72.30(c)(5)," dated March 17, 2005,[1] this letter submits documentation adequate to demonstrate that, as applicable, funding provided by the Trojan Independent Spent Fuel Storage Installation (ISFSI) co-owners for Trojan ISFSI decommissioning has been approved for recovery in rates by a ratemaking authority. As specified in the NRC's March 17, 2005, letter and the accompanying Safety Evaluation Report and Notice of Issuance (collectively referred to herein as the exemption approval), this documentation is submitted within 30 days of the issuance of the NRC's grant of exemption. Therefore, as detailed further below, this letter and its enclosures satisfy Condition 1 of the NRC's March 17, 2005, exemption approval, such that the NRC's exemption approval may be considered effective.

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[1] The NRC's exemption approval was in response to PGE Letter No. VPN-036-2004 dated April 29, 2004, whereby PGE requested a specific exemption, on behalf of the Trojan ISFSI co-owners, from the financial assurance requirements of 10 CFR 72.30(c). This exemption was requested to the extent that following termination of the Trojan Nuclear Plant license issued under 10 CFR 50, the requirement of 10 CFR 72.30(c)(5) may continue to be applied to provide decommissioning financial assurance for the Trojan ISFSI.

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It is noted that the NRC's March 17, 2005, exemption approval is worded such that the partial exemption from the requirement of 10 CFR 72.30(c)(5) is granted to "PGE, the Trojan ISFSI licensee." It is hereby clarified that the Trojan ISFSI is co-owned by PGE, the City of Eugene through the Eugene Water & Electric Board (EWEB), and Pacific Power & Light/PacifiCorp (PacifiCorp),[2] and that PGE, EWEB, and PacifiCorp are collectively named as "Licensee" on Trojan ISFSI License No. SNM-2509. As described further below, it is further clarified that the NRC's exemption approval is only intended to be applied by two of the three Trojan ISFSI co-owners – PGE and PacifiCorp – for their respective ownership shares of Trojan ISFSI decommissioning costs. PGE believes that these clarifications do not materially impact the NRC's March 17, 2005, exemption approval since, consistent with the exemption approval wording, the partial exemption will be implemented only by the Trojan ISFSI licensee as specified in Trojan ISFSI License No. SNM-2509.

The NRC's March 17, 2005, exemption approval specifies that the exemption is to be effective only upon satisfaction of the following condition, referred to as Condition 1 in the NRC's exemption approval:

> *[T]he exemption shall not become effective until the licensee submits, within 30 days of the issuance of this grant of exemption, documentation adequate to demonstrate that funding for the Trojan ISFSI decommissioning has been approved for recovery in rates by a rate making authority.*

The documentation required by the NRC's Condition 1 as cited above is only required and provided by this letter and its enclosures for the two Trojan ISFSI co-owners – PGE and PacifiCorp – that are anticipated to implement the NRC-approved partial exemption to 10 CFR 72.30(c)(5). As allowed by 10 CFR 72.30(c)(4), BPA, as a Federal government entity fulfilling the decommissioning funding obligations of EWEB, a licensee, will continue to provide financial assurance for Trojan ISFSI decommissioning in the form of a statement of intent indicating that decommissioning funds will be obtained when necessary. With BPA's continued use of a statement of intent to cover its ownership share of Trojan ISFSI decommissioning costs as allowed by 10 CFR 72.30(c)(4), BPA has no need to apply the NRC's exemption approval.

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[2] As detailed in PGE-1069, "Trojan ISFSI Safety Analysis Report," Section 1.1, "Introduction," and Section 9.8.2.2, "Decommissioning Funding Plan," the Trojan ISFSI is jointly owned by PGE (67.5 percent), the City of Eugene through the EWEB (30 percent), and PacifiCorp (2.5 percent). As discussed in PGE-1069, Section 9.8.2.2.2, "EWEB/BPA Funding," the Bonneville Power Administration (BPA) is obligated through Net Billing Agreements to fund EWEB's 30 percent share of the total Trojan ISFSI decommissioning costs. PGE is the principal owner and has responsibility for maintaining the Trojan ISFSI.

As detailed in PGE-1069, Section 9.8.2.2.1, "PGE Funding," and 9.8.2.2.3, "PP&L Funding," PGE and PacifiCorp each maintains and makes periodic contributions to its own external sinking fund to cover its ownership share of Trojan ISFSI decommissioning costs. As stated in PGE-1069, Section 9.8.2.2.1, "PGE Funding," PGE recovers its 67.5 percent share of the total estimated Trojan ISFSI decommissioning costs through ratemaking regulation. This is documented in Oregon Public Utility Commission (OPUC) Order No. 95-322, entered March 29, 1995, on Docket UE 88, a copy of which is included as Enclosure I to this letter. Specifically, the OPUC approved the Trojan Nuclear Plant decommissioning and funding plans, which included construction, operation, and decommissioning of the ISFSI, and inclusion of these costs in rates. (*See* OPUC Order No. 95-322 at 56, 57). The OPUC approved new PGE rate schedules via Order No. 01-777, entered August 31, 2001, on Docket UE 115. The new rate schedules do not impact the OPUC approval of PGE's decommissioning and funding plans for inclusion in the rate base as specified in Order No. 95-322. A copy of OPUC Order No. 01-777 is included as Enclosure II to this letter.

As stated in PGE-1069, Section 9.8.2.2.3, "PP&L Funding," PacifiCorp also recovers its 2.5 percent share of the total estimated Trojan ISFSI decommissioning costs through ratemaking regulation. PacifiCorp relies upon the above-cited OPUC Order No. 95-322, entered March 29, 1995, on Docket UE 88, a copy of which is included as Enclosure I to this letter. PacifiCorp has included Trojan ISFSI decommissioning costs in ratemaking proceedings since that date. These proceedings include Dockets UE 94, UE 111, UE 116, and UE 147. The OPUC reiterated in Order No 03-528 entered August 26, 2003, on Docket UE 147:

> *We have reviewed the stipulation, the testimony, and the supporting exhibits. We find that the stipulation is a fair and reasonable resolution of all issues in this docket. The stipulation, its Attachments A and B, and the stipulating parties' Exhibit 106, are attached to this order as Appendix A and incorporated herein. Exhibit 106 contains several schedules that summarize the stipulated revenue requirement adjustments from PacifiCorp's filed case in this docket. Page 1 replicates Attachment A to the stipulation and is not included. Pages 2 through 3 represent the stipulated adjustments and assumptions for the test period (the 12 months ending March 31, 2004). Page 4 contains the rate of return and revenue sensitive costs. Pages 5 through 8 show the revenue, expense, and rate base changes associated with each adjustment.* ***Except as specifically set forth in the adjustments, PacifiCorp's initial revenue requirement and all its components are accepted as filed. [Emphasis added]"***

A copy of OPUC Order No 03-528 on Docket UE 147, which incorporates the wording excerpted above, is included as Enclosure III to this letter.

As described above, the documentation submitted by this letter is adequate to demonstrate that, as applicable, funding provided by the Trojan ISFSI co-owners for Trojan ISFSI decommissioning has been approved for recovery in rates by a ratemaking authority. As specified in the NRC's March 17, 2005, exemption approval, PGE is submitting this documentation within 30 days of the issuance of the NRC's grant of exemption. Therefore, as detailed above, this letter and its enclosures satisfy Condition 1 of the NRC's March 17, 2005, exemption approval, such that the NRC's exemption approval may be considered effective.

Finally, it is noted that the NRC's March 17, 2005, exemption approval includes a "Condition 2" specifying that the exemption shall cease to be effective in the event that funds remaining to be placed into the Trojan ISFSI decommissioning external sinking fund are no longer approved for recovery in rates by a competent rate regulating authority. PGE hereby acknowledges Condition 2 of the NRC's exemption approval, such that in the future, if funds remaining to be placed into PGE's external sinking fund to cover PGE's 67.5 percent ownership share of Trojan ISFSI decommissioning costs are no longer approved for recovery in rates by a competent rate regulating authority (currently OPUC), the subject exemption will be considered no longer effective for and may no longer be implemented by PGE. Similarly, if funds remaining to be placed into Pacificorp's external sinking fund to cover PacifiCorp's 2.5 percent ownership share of Trojan ISFSI decommissioning costs are no longer approved for recovery in rates by a competent rate regulating authority (currently OPUC), the subject exemption will be considered no longer effective for and may no longer be implemented by PacifiCorp.

If you have any questions regarding this correspondence, please contact Mr. Jay P. Fischer, Trojan ISFSI Manager, at (503) 556-7030.

Sincerely,

Stephen M. Quennoz
Vice President, Generation

c: C. M. Regan, NRC, NMSS, SFPO
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D. Stewart-Smith, ODOE
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ENCLOSURE I TO VPN-002-2005

OPUC ORDER NO. 95-322, ENTERED MARCH 29, 1995, IN DOCKET UE 88

ORDER NO. 95-322

ENTERED MAR 29 1995

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 88

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

TABLE OF CONTENTS

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GLOSSARY
OF ABBREVIATIONS

A&G	Administrative and general
BPA	Bonneville Power Administration
BWR	Boiling water reactor
CO_2	Carbon dioxide
CP	Coincident peak
CUB	Citizens' Utility Board
DSM	Demand-side management
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
HVEA	High-value electrical applications
KW	Kilowatt
KWh	Kilowatt hour
LCP	Least-cost plan
LRIC	Long-run incremental cost
MTI	Maintenance Team Inspection
MW	Megawatt
MWh	Megawatt hour
NCP	Noncoincident peak
NRC	Nuclear Regulatory Commission
NWPPC	Northwest Power Planning Council
O&M	Operations and maintenance
OCEUR	Oregon Committee for Equitable Utility Rates
ODOE	Oregon Department of Energy
PGC	Portland General Corporation
PGE	Portland General Electric Company
PPC	Public Power Council
PWR	Pressurized water reactor
QA	Quality assurance
SALP	Systematic Assessment of Licensee Performance
TBA	Theodore Barry & Associates
TMI	Three-Mile Island
URP	Utility Reform Project
USDOE	United States Department of Energy

ORDER NO. 95-32

ENTERED MAR 29 1995

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 88

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

SUMMARY

This order approves new rate schedules for Portland General Electric Company (PGE). Under the new schedules, PGE's rates increase approximately 5.8 percent overall. PGE's original filing, which included a proposal to accelerate the Boardman gain amortization, sought an increase in revenues of $58,974,927 for 1995, and $60,783,781 for 1996. PGE subsequently withdrew its Boardman proposal, which increased the company's revenue need to $92,275,240 in 1995 and $95,105,468 in 1996. In this order, the Commission grants PGE an increase in revenues of $50,970,243 for 1995 and $51,812,359 for 1996.

Undepreciated Trojan Investment. The dominant issue in this docket is the allocation of undepreciated investment and other costs resulting from the premature closure of the Trojan Nuclear Power Plant (Trojan).

In January 1993, PGE retired the 1200 megawatt (MW) plant, which was licensed to operate until 2011. Degradation of the plant's steam generator tubes led PGE to retire the plant 19 years before the expiration of its 35-year license life. As of January 1, 1995, PGE's net undepreciated investment in Trojan totaled approximately $288 million. In this proceeding, PGE seeks full recovery of and return on that undepreciated investment, plus other costs related to service.

We reject PGE's request for full recovery of Trojan costs. We conclude that the allocation of the Trojan costs is properly determined by a "net benefits" analysis. A net benefits analysis compares the costs of a plant's continued operation with the costs associated with retiring the plant plus the expected long-term costs of replacing the plant's output. The purpose of a net benefits test is to identify the point at which ratepayers are indifferent between the options of continued operation of Trojan and shutdown and construction or acquisition of replacement resources.

- Full recovery of undepreciated Trojan costs is not guaranteed to PGE, nor is it required of the Commission. Granting full recovery in rates where there is not a net benefit to ratepayers would insulate the utility from risk no matter what its actions. On the other hand, granting no recovery of undepreciated investment would not encourage PGE to engage in prudent management and responsible least-cost planning, goals the Commission wishes to promote. The net benefits analysis is a tool to determine where ratepayers are held harmless for imprudent operation or management of Trojan, and to share costs between ratepayers and shareholders on that basis.

The Commission staff (staff) conducted a net benefits analysis, using PGE's least-cost plan (LCP) as a starting point. The final result of PGE's least-cost planning process indicated that immediately closing Trojan was the least-cost option. The LCP, however, considered the plant as it actually existed and projected those costs forward to 2011. To determine whether there was a net benefit to ratepayers from closing Trojan, staff sought to determine whether the costs on which PGE's least-cost planning process was based would have been allowed in rates. If PGE's LCP projections were based on costs that had been driven up by management problems, for instance, the net benefits analysis would disallow the costs if they were imprudently incurred.

Staff hired an independent consulting firm, Theodore Barry and Associates (TBA), to evaluate whether the costs of operating Trojan were prudently incurred. TBA assessed the reasonableness of PGE's operation and management of Trojan from the plant's initial commercial operation in 1976 through its current delicensing and decommissioning activities. TBA explored Trojan's comparative performance, reviewed management issues, and analyzed the steam generator issue. Its examination focused on whether PGE's actions, based on all the information PGE knew or should have known at the time, were reasonable and prudent in light of all the circumstances. TBA did not base conclusions on hindsight or knowledge acquired after the fact, and recognized that one or more courses of action may be reasonable in a given set of circumstances.

TBA also quantified the effects of PGE's management and operation deficiencies, and staff projected TBA's figures out over the period from 1995 to 2011, a period beginning with the first test year in this rate case and running through Trojan's originally scheduled closure. Staff compared these imputed costs with the cost of replacement resources to determine whether there was a net benefit from closing Trojan.

After an examination of the net benefits analysis, we conclude that the premature closure of Trojan resulted in a negative net benefit of approximately $20.4 million. We find that continued operation of Trojan would have cost less than immediate shutdown but for steam generator defects and management problems at Trojan. Management problems resulted in avoidable costs that should be borne by shareholders, not ratepayers.

We adopt TBA's finding that PGE behaved prudently with respect to the steam generator degradation. However, we disallow the steam generator costs incurred since 1991 and exclude the cost of replacing the steam generators from the imputed costs of running Trojan in the net benefits analysis. Although PGE's behavior was not faulty, PGE and the ratepayers are the only two parties to whom we can assign or impute steam-generator costs. As between those two parties, PGE is better situated to recover its costs from the manufacturer of the steam generators. Moreover, it is fair that shareholders bear some of the consequences of management investment decisions.

To hold PGE's ratepayers harmless for the effects of steam generator defects and management failures, we are disallowing recovery in rates of $20.4 million of the company's remaining investment in Trojan.

Post-1991 Capital Expenditures. We also disallow PGE's post-1991 capital expenditures to repair Trojan's steam generators and costs for the purchase of a spare nuclear reactor coolant pump. Although we find that PGE acted prudently with regard to its maintenance and operation of the steam generators, PGE is better situated to pursue remedies for any manufacturing defects against Westinghouse, the steam generator manufacturer, than are the ratepayers. PGE's purchase of the spare reactor coolant pump was not prudent and will not be allowed in rates. These disallowances total an additional $17.1 million, for a total Trojan-related disallowance of $37.5 million.

These conclusions result in a disallowance of 13.0 percent of the remaining Trojan costs, which will be borne by shareholders, not ratepayers. That result approximates a scenario in which Trojan was reasonably operated and managed. In the main, the disallowances correct for avoidable costs.

Decommissioning and Transition Costs. In this order, we also approve funds to decommission Trojan and to pay for the transition to shutdown. Decommissioning costs are the costs of physically dismantling the plant and packaging and storing the radioactive components and spent fuel. Transition costs are the operations and maintenance (O&M) and administrative and general (A&G) costs associated with plant closure.

PGE would incur decommissioning and transition costs regardless of when the plant was taken out of service, and the company has already been paying into a decommissioning fund. Because Trojan was shut down before the end of its license life, however, payments into the fund will have to increase for a time. Even with the increase in annual contribution, PGE will have to borrow to bridge its needs. As currently estimated, however, the cash flows will eventually be sufficient to fund the cost of decommissioning including repayment of the interim financing.

PGE has submitted a decommissioning plan for approval by the Nuclear Regulatory Commission (NRC). We approve PGE's plan subject to our review and monitoring of costs. There are a great many unknowns as regards decommissioning, and we need to retain the flexibility to modify PGE's plan if circumstances change significantly.

Decoupling. Another major issue in this docket is decoupling. Decoupling is a mechanism that eliminates the automatic connection between utility sales and profits. Breaking that connection is designed to encourage utilities to find cost-effective ways of reducing sales and conserving energy. If sales are linked to profits, a utility has every incentive to keep sales, and hence energy consumption, high.

Decoupling creates a mechanism to adjust for actual sales deviating from a preestablished level. A utility cannot increase its earnings by increasing sales, because additional sales margins are returned to ratepayers and the utility's net revenues are reset to the preestablished level. If the utility's revenues are less than forecast, the decoupling mechanism would restore those lost margins so that net revenues are again adjusted to reflect the preestablished level. The company does not gain or lose net revenues by selling larger or smaller amounts of power. The key step in decoupling is to establish the revenue targets.

In Order No. 92-1673, the majority of the Commission directed PGE to develop a decoupling mechanism suitable to its circumstances. Working as part of a collaborative, PGE designed a process that uses a two-year test period to establish revenue targets and deals with monthly revenue benchmarks, weather normalization, rate spread, and other issues.

At issue in this docket is whether and how to implement decoupling. Some parties argue that decoupling has not proven to be as effective as hoped in other jurisdictions. Some contend that forecasting over the two-year test period introduces too much uncertainty. Other parties argue for decoupling, but suggest different ways of treating rate spread or other features of the collaborative's plan.

A majority of the Commission finds that decoupling should be implemented. It is a relatively simple mechanism to remove a variety of perverse incentives inherent in the existing structure of rate regulation and it has low administrative costs. Its benefits clearly outweigh its disadvantages. Chairman Smith writes separately in dissent on this issue.

We adopt the collaborative's mechanism, subject to certain reporting and monitoring requirements. The reporting requirements are designed to make it easier to administer and review the mechanism. The monitoring requirements are designed to protect ratepayers from the potential problem of a decline in the level of PGE's service.

Rate Spread. In setting electric utility rates, this Commission has traditionally been guided by the cost of serving various customer classes, as measured by marginal costs. The marginal cost study approved in this order indicates that commercial and industrial customers pay a higher rate relative to the costs of providing service than residential customers.

In this order, we reaffirm the use of a "4-to-1" rate spread methodology to help set rates more in line with the actual costs caused by each customer class. This 4-to-1 methodology, which was adopted in PGE's last general rate case (UE 79), assigns residential customers a percentage increase of four times that assigned to medium and large commercial and industrial customers. This rate spread methodology will not eliminate the current rate disparity, but will achieve a more balanced distribution of the costs of service without subjecting residential customers to rate shock.

Other Issues. Commission staff asked the Commission to impose on PGE an additional reduction in discretionary costs (operating and maintenance expense accounts excluding Trojan O&M, amortization of energy efficient balances, uncollectible accounts, regulatory expenses, and rents) if the Commission found that PGE's cost reduction efforts were insufficiently diligent in the circumstances. We have imposed an additional one percent cost reduction on PGE, which reduces PGE's revenue requirement by approximately $1.6 million in each test year.

Most other major issues in this docket were resolved by stipulation between staff and PGE. We have reviewed these stipulations carefully, find that they are reasonable, and adopt them.

Overview of PGE's cost structure. This proceeding used a two-year test period to comport with the decoupling approach suggested by PGE's collaborative on decoupling. Due to the closure of Trojan, PGE's cost structure has changed significantly. The major factor causing the rate change authorized by this order involves power supply costs. As compared with the costs adopted in PGE's last rate order (UE 79, Order No. 91-186), fixed operation and maintenance costs decrease by $49.8 million for 1995 and by $47.6 million for 1996. However, power supply costs increase by $147.7 million for 1995 and by $152.7 million for 1996. Both of these factors are affected significantly, but not exclusively, by the closure of Trojan. Other factors offset to some extent the increases in costs, notably a lower rate of return to stockholders due to more favorable capital markets. In addition, the Commission has disallowed certain of the unrecovered Trojan costs. The decision on the Trojan cost recovery issue has the effect of reducing PGE's request by $9.7 million for 1995 and by $9.3 million for 1996.

INTRODUCTION

Procedural Background

On November 9, 1993, PGE filed Advice No. 93-26, a general tariff revision designed to increase rates to its Oregon electric retail customers, to be effective December 8, 1993. PGE's proposed price schedules are based on the company's expected revenue requirement for a two-year test period covering 1995 and 1996. The two-year test period reflects the decoupling mechanism designed by PGE and a collaborative work group pursuant to Order No. 92-1673.

On December 7, 1993, we found good and sufficient cause to investigate the propriety and reasonableness of the rates and initially ordered the suspension of Advice No. 93-26 for a period of six months. *See* Order No. 93-1754. Shortly thereafter, PGE waived the statutory suspension period and, on June 1, 1994, we ordered a further suspension of the Advice until January 1, 1995. *See* Order No. 94-899.

Prehearing Conference

On December 13, 1993, Ruth Crowley, a Hearings Officer for the Commission, held a prehearing conference in Salem, Oregon, to identify parties and interested persons and to adopt a procedural schedule. A list of the parties to this proceeding is set forth in Appendix A.

Public Comment Hearings

In February 1994, we held public comment hearings in Portland, Gresham, Aloha, and Salem. At each hearing, a representative of PGE made an informal presentation explaining the terms of the proposed rate schedules and other aspects of the filing. A member of the Commission staff also appeared to explain staff's role in this proceeding and to answer questions from the public. Many PGE customers and interest groups attended the hearings and testified in opposition to the proposed rate increase. During the course of this proceeding, we also received numerous written comments from the public opposing PGE's proposed tariffs.

Bifurcation

On March 21, 1994, staff moved to amend the schedule and to defer examination of issues related to PGE's investment in the Trojan Nuclear Power Plant and cost of capital to a later phase of this proceeding. Staff requested the bifurcation to allow time to hire a consultant and time for the consultant to review Trojan-related issues.[1] On May 3, 1994, the Hearings Officers granted the motion and bifurcated this proceeding into Phase I and Phase II.

UM 692 and Further Extension of Suspension Period

On May 26, 1994, staff moved to further amend the schedule to allow additional time for its consultant to complete work. Staff concurrently filed a motion for an order authorizing PGE to use, upon the expiration of the suspension period, deferred accounting

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[1] For purposes of this proceeding, Trojan-related issues are defined to include any issue encompassed by Docket No. DR 10, Order Nos. 93-1117 and 93-1763.

treatment for increased revenues resulting from the implementation of PGE's revised tariffs.

Staff subsequently withdrew its motions. On July 29, 1994, PGE applied to defer for later ratemaking treatment 40 percent of the increased power costs resulting from the closure of Trojan for the period from January 1, 1995, until March 31, 1995, or the effective date of new tariffs approved in this proceeding, whichever is earlier. We docketed PGE's application as UM 692 and consolidated it with this proceeding. On September 30, 1994, we granted PGE's request for deferral of costs. *See* Order No. 94-1456. With approval of its application, PGE agreed to stipulate to a further extension of the suspension period to no later than March 31, 1995.

PHASE I

Issues List

After a review of PGE's tariff filing, staff identified 44 potential issues in what has been designated as Phase I of this proceeding. Staff listed those issues numerically in its preliminary issues list, filed on May 3, 1994. We use staff's numbering system in our discussion of those issues. A complete issue list is found on page 1 of Appendix F, Adjustment Summary, attached.

Stipulations

On July 1, 1994, PGE and staff submitted a stipulation intended to resolve many of the disputed issues in this portion of the proceeding, subject to our approval. The stipulation is attached as Appendix B. The stipulation was supported by joint testimony of Ray Lambeth of staff and Kelley Marold of PGE on numerous revenue, expense and rate base issues.

On July 15, 1994, PGE and staff submitted a stipulation supplement intended to resolve additional disputed issues not covered in the first stipulation. The stipulation supplement is attached as Appendix C. The stipulation was supported by joint testimony of Lynn Plamondon of staff and Chris Ryder of PGE.

On February 27, 1995, PGE and staff submitted an additional stipulation intended to resolve issues relating to Issue S-13: Variable Power Costs. The additional stipulation is attached as Appendix D.

All stipulations and supporting testimony were entered into the record of this proceeding as evidence pursuant to OAR 860-14-085(1).

Evidentiary Hearing

On July 14, 1994, Hearings Officers Ruth Crowley and Michael Grant held a Phase I evidentiary hearing in Salem, Oregon. Randy Childress and Melinda Horgan, Attorneys at Law, appeared on behalf of PGE. Paul Graham, Mike Weirich, and Kimberly Cobrain, Assistant Attorneys General, appeared on behalf of staff. Grant Tanner, Attorney at Law, appeared on behalf of the Oregon Committee for Equitable Utility Rates (OCEUR). John Stephens, Attorney at Law, appeared on behalf of the Citizens' Utility Board (CUB). Phil Carver appeared on behalf of the Oregon Department of Energy (ODOE).

Based on the record in these proceedings, we make the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Stipulated Issues

The Phase I stipulations cover most of the issues identified by staff in this portion of the proceeding. ODOE and OCEUR are not parties to the stipulations and object to portions of the proposed resolution of Issue S-44: Rate Design. OCEUR also challenges the proposed resolution of Issue S-13: Variable Power Costs, and Issue S-37: Boardman Gain Acceleration. Accordingly, we will treat issues S-13, S-37 and S-44 as a contested issues and address them with the other issues not covered in the proposed stipulations.

We have reviewed the Phase I stipulations with regard to the other noncontested issues (S-1 through S-12, S-14, S-17 through S-28 except for one issue in S-20, S-30, S-31, S-33, S-34 through S-36, S-39, S-40, S-42 and S-43). We find the stipulations on these issues reasonable. Accordingly, the stipulations on those issues, set forth in Appendices B, C and D, are adopted.

Contested Issues

The Phase I stipulation did not cover six identified issues (S-15: Wage and Salary; S-20: Medical Insurance Pooling; S-29: HVEA Promotions; S-32: PGC Allocations; S-38: Decoupling; and S-41, LRIC and Rate Spread). Furthermore, as discussed above, issues S-13: Variable Power Costs, S-37: Boardman Gain Acceleration, and S-44: Rate Design, are treated as contested issues. We address these nine issues separately in numerical order.

Applicable Law

As the petitioner in this rate case, PGE has the burden of proof on all issues. ORS 757.210 provides that, in a rate case, "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable."

S-13: Variable Power Costs

PGE incurs variable power costs to meet its retail and firm wholesale requirements and to make economic wholesale sales in the secondary market. To estimate its variable power costs for the two-year test period, PGE used PROSCREEN, a computer forecasting model.[2]

PGE and staff entered into a stipulation with respect to PGE's variable power costs. The parties propose to include in UE 88 base rates variable costs savings expected from the commercial operation of the Coyote Springs generating plant using a forecast in-service date of December 15, 1995. The parties also agree that PGE may file proposed revised rates to address a change in BPA's transmission and power rates through a tracking procedure when such change occurs. As a result of those proposals, PGE and staff further agree that the following amounts are a reasonable forecast of variable power costs for the test period: $304,624,300 (1995); $310,103,700 (1996).

OCEUR is not a party to that stipulation, however, and objects to the use of the PROSCREEN model because the model was developed for use in thermal-based systems. OCEUR does not suggest an alternative but urges caution in use of the model. For 1996, OCEUR proposes to increase the 1995 estimate only by a load growth factor. We find that proposal unacceptable, because OCEUR's approach does not rigorously forecast power costs for 1996 and hence is not factually based .

We have reviewed the stipulation between staff and PGE on variable power costs and find it reasonable. We adopt that stipulation, attached as Appendix D.

S-15: Wage and Salary

Staff proposes certain adjustments to PGE's filing with respect to estimated increases in wages and salaries. Specifically, staff recommends reductions in straight-time labor of $504,691 in 1995 and $923,640 in 1996, and allocates those reductions between operations and maintenance expense and capital. Staff also recommends a reduction in related payroll tax expense.

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[2] The PROSCREEN model calculates a power cost forecast based primarily on: 1) PGE's nondispatchable firm purchases and sales; 2) hydro capacity, both average energy and peaking, under different water conditions and based on PGE and regional hydro resources; 3) hourly loads of PGE, the Northwest, and California; 4) the variable costs of PGE's thermal plants; and 5) the marginal cost curves of other resources in the Northwest and California. The model then applies the Network Economy Interchange logic to make purchases and sales that minimize the marginal cost of the entire system, making as many economic transactions as possible prior to dispatching PGE's plants and other dispatchable resources and making purchases to meet the remaining load.

Staff and PGE arrive at their positions by using two different analytical methods. PGE relies on a market-based approach to determine its labor budget. PGE first defined five labor markets, differentiated in terms of size and demographics, in which it competes for employees. For each market, PGE reviews annual surveys from various sources to determine competitive base pay rates for its employees.

Staff relies on a three-year wage and salary formula to estimate appropriate payroll levels. As a starting point, staff's formula uses PGE's actual nonunion average wage and salary level for 1992 and 1993. From there, staff applies the Consumer Price Index change for each of the three subsequent years to establish a forecast of test-year wage and salary levels. In staff's method, if PGE's projected wage and salary level is within ten percent of staff's projection, the difference between projections is shared equally between customers and shareholders. Outside the ten percent band, shareholders keep all the benefit or pay all the cost.

We find the three-year wage and salary formula more reasonable than PGE's approach for this proceeding and adopt staff's recommendations. As staff points out, this Commission has relied on staff's model for over ten years to monitor energy utilities' wages and salaries for both general rate cases and earning tests associated with deferred accounting. The current model produces a reasonable and reliable result.

PGE faults staff's model for not being market based. Staff's model is based on market data. Its starting point is actual PGE wages for 1992 and 1993. Moreover, staff's method of sharing the difference between the two payroll projections equally between ratepayers and shareholders also allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.

Although we adopt staff's method for this proceeding, we do not preclude more extensive use of market data in future proceedings. We will not direct staff to investigate further the use of market data, as PGE requests. However, the company may introduce appropriate market data in support of its filings in the future.

S-20: Medical Insurance

Issue S-20 is covered by the stipulation with the exception of staff's proposal that PGE explore the possibility of becoming part of a larger insurance pool to reduce its medical insurance costs. Staff asks us to order PGE to assess the possibility of pooling arrangements with other companies. PGE objects and argues that the possibility of national health care reform creates uncertainty in the medical insurance area and notes that it unsuccessfully attempted medical insurance pooling in the early 1980s.

Staff counters that it requires only a feasibility study. Staff urges that PGE should submit a proposal for an assessment study within 45 days of the entry of the order in this docket. PGE opposes the requirement to perform an additional study on pooling costs because the requirement duplicates or contradicts other PGE efforts in this area;

because staff's proposal is unclear; and because the required study may be very costly and time consuming. PGE argues that it should be allowed to provide staff a status report on its efforts to reduce medical insurance costs within 90 days from the date of this order. Once staff has had an opportunity to review the report, the Commission may hold a hearing to see what additional steps are needed to implement insurance cost reduction.

PGE's suggestion is the more efficient and reasonable approach. We adopt PGE's proposal for exploring ways of reducing medical insurance expenses. PGE's status report will be due within 90 days from the date of entry of this order.

S-29: HVEA Promotions

PGE's proposed revenue requirements for 1995 and 1996 include over $1 million each year to provide customers with information about High-Value Electrical Applications (HVEA). These applications include electric forklifts, electric lawnmowers and grass trimmers, electric barbecues, and dual-fuel heat pumps. PGE contends that providing customers with information about HVEA is a valuable customer service and proposes to budget related expenditures under Federal Energy Regulatory Commission (FERC) Account 908.

Staff objects to PGE's proposal and recommends that the Commission disallow all expenses relating to HVEA promotions. Staff contends that the HVEA activities are intended to either promote or retain load. For that reason, staff argues that the costs related to the HVEA marketing activities are more appropriately treated as promotional expenses under FERC Account 912.

To recover HVEA expenses, PGE must demonstrate that the promotional activities are reasonable by quantifying net ratepayer benefits. In Docket No. UG 81, the Commission recognized that ratepayer benefits must be established by "a showing that the specific expenditures incurred provided a recognizable benefit to the people from whom the utility seeks reimbursement. . . . It may be difficult to quantify benefits, but the utility company needs to show the Commission that there is a sound basis for passing the costs on to the ratepayers." Order No. 89-1372 at 7.

After a review of PGE's testimony, exhibits, work papers, and other evidence submitted in this matter, we conclude that PGE has failed to establish specific benefits to ratepayers from HVEA expenditures. Although PGE maintains that HVEA activities are a customer satisfaction strategy designed to help the company move into a more competitive environment, it acknowledges that HVEA may increase the use of electricity by up to an average of four to five MW per year. Thus, while the information provided may prove useful to some customers, a primary purpose of the activities is to create new customers or increase sales to existing customers. Because PGE has not demonstrated that the promotion of HVEA will provide specific benefits to its ratepayers, we adopt staff's recommendation that these costs not be allowed.

In reaching this decision, we note staff's concerns that PGE is inconsistent in promoting both energy efficiency and load growth when the company is acquiring new resources. PGE's efforts to promote load growth may undermine its ability to promote customer adoption of energy efficiency measures. We recognize that there are some circumstances in which the increased use of electricity can provide benefits that may not directly relate to rates, such as environmental benefits. PGE, however, must provide sufficient evidence to support a finding that those benefits exist.

S-32: PGC Allocation

PGE's filing allocates certain joint and common costs incurred by Portland General Corporation (PGC) to PGE, a wholly owned subsidiary. This issue concerns allocations to PGE of PGC's Board of Directors costs and PGC's Executive costs. PGE proposes to change its cost allocation method from the direct labor costs method to the Equity Method for Board of Directors costs and the Massachusetts Formula for the Executive costs. Staff has usually used the direct labor costs method. The Commission adopted that method in UE 79,Order No. 91-186. PGE's filing for FERC Account Nos. 921 (Office Supplies and Expenses), 926 (Employee Pensions and Benefits), and 408.1 (Taxes Other Than income Taxes) was $6,294,769 for 1995 and $6,844,271 for 1996. Those accounts reflect PGC cost allocations.

The Equity Method distributes costs on the proportionate investment of the parent company, PGC, in its various subsidiaries. The Massachusetts Formula distributes costs on an equal weighting of subsidiaries' payroll, revenue, and assets. PGE did not present reasons for changing from the direct labor costs method.

Staff argues that the proposed methods are inappropriate for the S-32 cost allocation categories. PGE's revision with respect to the Equity Method, staff contends, is based on assertions unsupported by verifiable cost causation linkages. There should be a high degree of correlation between PGC employees' time and the PGC Board of Directors' time allocation, according to staff, because both groups are concerned with shareholder wealth maximization. Staff further argues that if PGC has nonoperating subsidiaries with investment but no demand on PGC employees' or directors' time, the existing method will achieve a more correct allocation of cost than the Equity Method.

Staff points out that the Massachusetts Formula could be a fair and reasonable method for homogeneous subsidiaries, as measured by line of business and maturity. Staff contends that that is not the case here, however, because PGE has inherent biases as to capital and labor intensity when compared to the nonregulated subsidiaries of PGC. These biases, according to staff, skew costs to the utility and provide an improper cross-subsidization. Staff also expresses reservations about inclusion of revenues, which are cost derivative, not cost causative, in the formula. Staff takes the position that the best reflection of effort and resource expenditures by the parent is its directly assigned labor expense. Staff has recalculated PGE's original filing for FERC Account Nos. 921, 926, and 408.1 to $5,793,297 for 1995 and $5,992,097 for 1996. Those reductions reflect corrections of inflation errors and eliminate the effects of PGE's proposed allocations revisions.

PGE does not counter staff's arguments. We are persuaded that staff is correct and adopt staff's adjustments to the PGC cost allocations.

S-38: Decoupling

Definition of Decoupling. Decoupling is a regulatory tool designed to eliminate disincentives for a utility to promote cost-effective energy conservation. Decoupling mechanisms break the link between profits and sales by creating a mechanism to adjust for actual sales deviating from a preestablished level. Under this mechanism, a utility cannot increase its earnings by increasing its sales, because additional sales margins are returned to ratepayers and the utility's net revenues are reset to the preestablished level. If the utility's revenues are less than forecast, the decoupling mechanism would restore those lost margins so that actual net revenues are again adjusted to reflect the preestablished level. Thus, the company does not gain or lose net revenues by selling larger or smaller amounts of power.

Decoupling Policy and Collaborative Recommendations. In 1991, the Commission opened an investigation docket, UM 409, to develop a set of policies that would encourage utilities to acquire cost-effective demand-side resources. In Order No. 92-1673, at 13, the majority of the Commission made a policy decision to decouple utility profits from sales levels:

> We are persuaded that the connection between profits and sales should be severed. As long as the regulatory system provides that increased sales may lead to increased profits, a conflict will exist between the motivation to sell energy and the motivation to promote reduction in energy consumption. No other change in the regulatory system can ensure that we will move toward the goals of this proceeding.

The Commission directed PGE to undertake collaborative processes to develop a decoupling mechanism suited to the company's particular circumstances. PGE, staff, and representatives of a broad group of interests worked together to develop a decoupling mechanism for PGE. The collaborative, as the working group was called, presented its mechanism at the Commission's April 20, 1993, public meeting.

To establish revenue targets for PGE, the collaborative decided to use a two-year test period. Revenue targets are to be set once for each two-year period, so that there is one rate change for the period. The mechanism also establishes monthly revenue benchmarks and incremental cost estimates; restates actual revenues and sales as if normal weather had occurred; implements decoupling-related rate adjustments every six months as needed; amortizes any decoupling adjustment over an 18-month period; spreads the decoupling adjustment among the customer classes using, in part, the rate spread adopted by the Commission in PGE's 1991 general rate order, Order No. 91-186 (UE 79); and caps the overall revenues collected from the decoupling rate adjustment at any time at 3 percent of base revenues.

How and Whether to Implement Decoupling. The Oregon Department of Energy (ODOE), and the Northwest Conservation Act Coalition (NCAC) do not oppose decoupling. Staff states that the Commission has already made the policy decision that profits should be decoupled from kilowatt hour (KWh) sales. Therefore, staff did not discuss whether decoupling should be implemented. PGE agrees to decoupling if the Commission finds that its benefits outweigh its disadvantages. PGE also conditioned its agreement on the Commission following PGE's request with respect to the treatment of variable power costs (Issue S-13). PGE signed a stipulation resolving that issue, so PGE's concerns in that regard have been met. ODOE and NCAC also support the collaborative's decoupling mechanism.

OCEUR raises a number of arguments against decoupling. First, OCEUR contends that decoupling abandons the regulatory premise that utility rates should be based on the utility's prudently incurred costs of providing service. It argues that decoupling not only leaves a utility indifferent to declining revenues from conservation, but also insulates it from revenue attrition resulting from any source, including warm weather, recession, or disappearing rate base. In short, OCEUR believes that decoupling makes a utility insensitive to costs and profits.

Second, OCEUR points out problems associated with decoupling, especially the difficulties of estimating costs for a two-year period with sufficient accuracy for ratemaking purposes. The two-year period, OCEUR contends, fails to account for the time value of money. Costs are estimated on a year-by-year basis and then averaged over two years. In a time of rising costs, this leads to collection of a greater amount in rates than is actually incurred for that year, and a subsequent lesser collection the second year. Therefore, OCEUR contends that the decoupling mechanism functions as an interest-free loan to the utility in such a case. OCEUR also believes that the mechanism gives the utility an incentive to overestimate its power costs in the second year of a two-year test period.

Staff noted that OCEUR's concern is less about decoupling than about accurately estimating variable power costs. Staff stated that the Commission frequently uses estimates of variable power costs in such areas as avoided costs and conservation cost effectiveness. Because these other areas are extensively scrutinized, staff does not believe an "error" exists in the methodology for estimating variable power costs and notes that OCEUR has not raised this concern in any of those other areas.

Finally, OCEUR contends that the decoupling mechanism allows the company to game the mechanism. OCEUR believes that the incremental costs used in the mechanism understate the "true" short-run variable cost. OCEUR contends that the company can inappropriately increase its profits through the decoupling mechanism by reducing its sales.

Consistent with its argument on Issues S-41 below, CUB requests that we undo the 4-to-1 rate spread for decoupling adjustments.

Disposition. We adopt the decoupling mechanism the collaborative presented, subject to the recommendations staff has made (see below). It is still the Commission's policy to encourage conservation by severing the link between sales levels and profits. The difficulties of forecasting a two-year test period are not significant enough to outweigh the potential benefits from decoupling.

Decoupling is an attempt to align the utility's financial interest with the interests of its customers. Decoupling removes the utility's incentive to promote new sales and does not provide utilities with an incentive to adopt ineffective demand-side management programs. The current system of regulation produces incentives for utilities to increase electricity sales and corresponding disincentives to the pursuit of energy efficiency. Because decoupling separates profits from fluctuating sales levels *regardless* of the cause of the changed sales, it addresses efficiency impacts resulting from *all* effects, including rate design, all utility-sponsored demand-side management activities, and all energy efficiency measures. Moreover, decoupling does not require sophisticated measurement or estimation. A utility that does not actually produce savings simply does not profit from demand-side management.

Decoupling does not take the next step and provide a positive incentive for good planning. But it does provide a relatively simple mechanism to remove a variety of short-term perverse incentives inherent in the existing regulatory structure.

Breaking the link between sales levels and profitability does not mean that the utility is left with no incentive to minimize costs and maximize profits. The utility can increase its profitability through activities not related to sales. Also, the collaborative's decoupling mechanism specifically chose to use expected rather than actual incremental power costs, giving the utility another opportunity to increase profits by minimizing its actual KWh costs.

The Commission is persuaded by staff's rebuttal of OCEUR's concerns about variable power costs. As to OCEUR's arguments about the time value of money, where rising costs are averaged over two years, the first year's actual average cost will be less than the two-year average, and the second year's actual average cost will be more than the two-year average. This is a natural outcome of averaging. This averaging also occurs in a single-year test year, the result being that a single set of rates for the test year will necessarily be overstated for the first six months and understated for the last six months. Normal regulatory practice does not make an adjustment to costs to take into account what may be considered an interest-free loan due to this type of stream of payments. As with other aspects of the collaborative's mechanism, the Commission is not inclined to dismantle the collaborative's recommendations. The Commission appreciates OCEUR's concern, however, and directs staff to consider this issue in future developments of regulatory mechanisms.

The fact that the decoupling mechanism presents the utility an incentive to inflate its second year's estimated costs raises a concern. However, we believe that problem has been contained by staff's monitoring of the costs in this docket. As to CUB's request, we will not dismantle the collaborative's recommendations piecemeal by changing the rate spread that the collaborative agreed on.

In terms of specific implementation, Paragraph 36 of the July 1, 1994, stipulation sets forth the agreement to use one set of weather normalization coefficients for both years of the test period.[3] Further, staff recommends that we require a decoupling tariff design that contains information on monthly revenues, incremental costs, and margins that result from this rate case. Having this information in the tariff will make the task of administering the mechanism easier, staff maintains, and will allow review of the mechanism. Staff also recommends that the tariff include information on the weather normalization procedure that staff and PGE have agreed on. No party opposes these recommendations about the tariff, and we adopt them.

Because PGE will no longer have the incentive to sell more KWh or to sell at higher prices the KWh it currently markets, we need to consider service quality to PGE's customers. To address the issue of service quality, staff also recommends that we direct staff to monitor PGE's service to protect ratepayers and assess the impacts of decoupling on the utility's behavior. No party opposes this recommendation, and we adopt it.

Paragraph 8 of the July 15, 1994, stipulation covers implementation of the decoupling mechanism. The mechanism functions as a comparison of benchmark net revenues to weather-adjusted actual net revenues. Revenue targets are based on the assumption that the new rates, to be set in this docket, are in effect. Consequently, PGE and staff agree that the decoupling comparison should occur when revenues reflect new rates. Accrual adjustments for decoupling should therefore not begin until the effective date of the new rates.

Incremental Power Costs. PGE and staff disagree on how to treat incremental power costs under the decoupling mechanism. Monthly incremental power costs are needed to determine the margin earned or lost because of changes in sales from those forecast in the rate case. The decoupling collaborative stated that these 24 monthly

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[3] Weather normalization coefficients are used to adjust sales and revenues to reflect a normal weather pattern. Using only one set of coefficients will reduce the cost and difficulty of implementing decoupling. It will obviate the need to update the coefficient at the end of 1995 and will ensure that the level of revenues set in the rate case and the decoupling adjustment mechanism will use the same factors to describe the effect of weather on sales.

estimates should be set in the rate case but did not specify a methodology.[4] In its filing, PGE proposed using the PROSCREEN model to determine incremental power costs, using the actual differences between forecast loads and weather-adjusted loads. Staff proposed generating incremental power cost estimates by averaging the incremental power costs associated with positive and negative load increments of the same size. We adopt staff's rather than PGE's proposal, because the use of estimated incremental power costs is consistent with the collaborative's recommendation.

Staff originally proposed using +/- 5 MW as the increment for purposes of estimating incremental power costs. PGE countered with a proposal of +/- 10 MW, an increment, PGE contends, that is large enough to ensure meaningful results. Staff does not object to the 10 MW figure, provided staff has the right to review PGE's calculation of estimates. Lack of such review could result in inaccurate incremental cost estimates that could create perverse sales incentives. We adopt the +/- 10 MW increment figure for estimating incremental power costs, and order that staff shall have the right to review PGE's calculation of estimates.

The February 27, 1995, variable power costs stipulation between PGE and staff could result in revisions in late 1995 or early 1996 to the monthly targets contained in the decoupling tariff.

S-37: Boardman Gain Amortization

PGE had originally proposed accelerating the Boardman gain amortization to three years instead of the 27-year period approved in UE 47/48, Order No. 87-1017. Staff opposed the proposal, and PGE withdrew it. OCEUR still supports acceleration of the Boardman gain amortization for ratemaking purposes.

OCEUR argues in favor of the acceleration because it believes that customers paid a disproportionate share of overall Boardman costs in the plant's early years. According to staff, that is true of every plant. The Commission allows return on unrecovered investment. In the early years of a plant, staff points out, unrecovered investment is large; later it shrinks. Staff contends that OCEUR's argument assumes without stating that PGE sold Boardman for more than the book value of the plant. In fact, staff maintains, PGE realized no profit from sale of the plant.

Staff is correct about the Boardman sale. *See* Order No. 87-1017 at 28. That order established the Boardman gain amortization and found that most of the money PGE received from the transaction represented profit from a wholesale power sale between

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[4] Incremental power cost estimates reflect the additional power cost incurred per MWh given a small increase or decrease in loads. The collaborative chose to use incremental power cost estimates developed in the rate case rather than actual power costs. The purpose of this choice was to give the utility an incentive to minimize its power costs. That is, if the utility can improve on the estimated power costs, its stockholders benefit, but if the actual power costs are greater than expected, the utility must shoulder the extra costs.

PGE and San Diego Gas & Electric. $51.3 million of the $78.7 million to be amortized came from the power sale. The power sale to San Diego Gas and Electric that generated the majority of the gain at issue was a system sale, and thus we continue to maintain that the gain be amortized as prescribed in Order No. 87-1017. We are persuaded by staff's argument and adopt the resolution of the issue contained in the Phase I stipulation, Appendix B at 13.

S-41: LRIC and Rate Spread

As part of its filing, PGE submitted a long-run incremental cost (LRIC) study. LRIC is a measure of the long-run costs or savings from providing one unit more or less of service. The Commission has traditionally used LRIC studies to determine cost causation and to help allocate those costs.

PGE's cost study indicates that commercial and industrial customers pay a higher rate relative to the cost of providing service than residential customers. The study, as revised by adjustments recommended by staff, shows that current residential rates collect 92.5 percent of average recovery of total LRIC, while large commercial and industrial rates collect 120.1 percent of the average. To help rectify this disparity and to achieve a more balanced distribution of the costs of service, PGE proposes to apply a "4-to-1" methodology in determining rate spread between customer classes. The 4-to-1 methodology assigns residential customers a percentage increase of four times that assigned to medium and large commercial and industrial customers. A 4-to-1 approach would increase residential rates to 95.6 percent of average recovery and reduce large commercial and industrial schedules to 113.0 percent of the average. The Commission adopted the 4-to-1 methodology in PGE's last general rate case. *See* UE 79, Order No. 91-186 at 25.

PGE's revised LRIC study and its proposed 4-to-1 rate spread are supported by all parties participating in Phase I of this proceeding with the exception of CUB. CUB argues that PGE's use of a "minimum system"[5] approach to allocate distribution costs in the LRIC study assigns too many of those costs to residential customers. CUB suggests the use of a "basic customer allocation"[6] method, which would assign a greater share of distribution costs to commercial and industrial customers. Using that approach to allocate distribution costs, CUB contends that a corrected cost study shows that residential customers would actually pay 102.6 percent of indexed costs under a 4-to-1 rate spread. Due to this fact, CUB argues that the marginal cost study does not support

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[5] The minimum system approach divides distribution costs between customer-related and demand-related costs by determining the cost of building a theoretical distribution system using the smallest size components. The costs of this minimum system, which includes poles, underground conduits, conductors, transformers, service drops, and meters, are defined as customer related. Additional costs associated with expanding the minimum-sized system to meet a customer's demand are defined as demand related.

[6] The basic customer allocation method treats distribution costs that vary directly with the addition or subtraction of a single customer as customer related. These exclusive customer cost components primarily consist of service drops and meters. All other distribution costs are considered demand related.

PGE's rate spread proposal and recommends that any increase in rates be spread equally among all rate classes.[7]

We are not persuaded by CUB's recommendation for two reasons. First, as noted by PGE, when CUB recalculated the marginal costs for residential customers in preparing its cost study, it failed to adjust the marginal costs for the nonresidential customer classes. That error led CUB to overstate the indexed percent of marginal costs for the residential class at 102.6 percent. Using CUB's estimates of marginal distribution and customer costs and recalculating marginal costs for the nonresidential classes, the corrected figure for residential customers under CUB's approach is 101.0 percent of indexed costs, under a 4-to-1 rate spread. Because that figure is based on PGE's original filing and does not reflect revenue requirement reductions and other adjustments embodied in the stipulation, we add that a 4-to-1 rate spread will not likely raise residential rates as high as that reduced figure.

Second, CUB failed to use the appropriate definition of demand in allocating distribution costs under the basic customer allocation approach. Under CUB's proposed methodology, any costs other than service drops and meters are classified as demand-related costs. In applying that method, however, CUB improperly assigned marginal costs using a coincident peak (CP)[8] allocator, rather than using a weighted allocation of distribution costs that considers both CP and noncoincident peak (NCP).[9] Because distribution facilities are primarily designed to meet a customer's maximum NCP, the costs associated with the system must be allocated on that basis. Thus, CUB's vastly different distribution cost allocation results from its different definition of demand, not from inherent differences between allocation methods. Had CUB used a correct allocator for distribution demand costs, its spread of distribution costs to various rate classes would have been similar to that of PGE's study.

We have reviewed PGE's revised LRIC study and find the minimum system approach appropriate for allocating distribution costs in this proceeding. PGE has used that methodology in the development of its marginal costs for over 15 years. Moreover, while no unanimity exists on the treatment of distribution costs, a study by the National

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[7] In its brief, CUB also implies that PGE is unconcerned about residential rate design due to the availability of residential exchange funds from the Bonneville Power Administration (BPA). The Commission addresses CUB's comments only to clarify that there is no relationship between rate spread and the residential exchange credit. The residential exchange credit is paid by BPA to investor-owned utilities based on the difference between the utility's average system cost and BPA's priority firm rate for its customer utilities. BPA, not the Commission, determines the amount of the credit. Rate spread is calculated by the Commission. That is a separate analysis that distributes the utility's revenue requirement among customer classes based on the costs incurred by the utility in serving that particular class of customers.

[8] CP is the measure of the maximum aggregrate customer usage at a single point of time during the year. This is the coincident point in time at which generation and transmission facilities are used to the maximum.

[9] NCP measures individual rate class or customer peak demand, which may be significantly higher that at the time of system coincident peak.

Economic Research Associates found that the minimum system approach was the most frequently used method in the treatment of distribution costs. Accordingly, we conclude that the revised LRIC study reasonably estimates marginal costs and should be used to guide rate spread and rate design.

We further conclude that PGE's revised rate study supports the 4-to-1 rate spread proposal. As noted above, the Commission previously adopted the use of a 4-to-1 methodology in PGE's last general rate case to help set rates more in line with the actual costs caused by each customer class. With increasing competition in the electric services industry, public policy dictates continued movement toward rate parity. We believe that the continued use of a 4-to-1 rate spread will help accomplish that goal without subjecting residential customers to rate shock.

In reaching these decisions, we request the parties to address and study other cost allocation methods for possible use in PGE's next general rate case. All marginal cost studies use simplifying assumptions and conventions to attempt to best estimate cost causation. While we have found that PGE's LRIC study reasonably estimates those costs and should be used in this rate proceeding, several parties, including PGE, OCEUR, and staff, have suggested possible improvements to the study. These suggested improvements include the use of a "facilities approach"[10] method for allocating distribution costs. In addressing possible adjustments to the marginal cost study, the parties should complete discussions in time to implement and recommend changes prior to PGE's next general rate case. PGE should take the lead in conducting such discussions.

S-44: Rate Design

PGE proposed several changes relating to its electric rate design. PGE's filing includes: (1) an increase in customer charges for the residential and small commercial classes; (2) the elimination of the seasonal differential in demand charges; (3) an increase in demand charges and reduction of energy charges for most commercial and industrial customers; (4) the addition of a time-of-day differential to energy charges for large commercial and industrial service (over 1 MW); and (5) an increase in power factor requirements.

Staff and PGE have stipulated that PGE should implement the proposed overall rate design, with the exception of proposed Schedules 103 (energy efficiency recovery adjustment) and 107 (adder for the Boardman sale refund adjustment), and the increase to the customer charge on Schedule 7 (residential service). The parties also agree that minor deviations may be necessary in implementing these rate design changes to achieve a

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[10] The facilities cost approach recognizes that distribution systems are designed using engineering standards that consider the number of customers and the expected loads of these customers. Costs are therefore determined on a cost-per-design-kilovolt-ampere basis.

smooth transition between rate schedules. The stipulated agreement is set forth in the July 1, 1994 Stipulation, paragraph 41 (Appendix B, attached).

ODOE and OCEUR are not parties to the stipulation and raise several issues related to PGE's proposed rate design. ODOE advocates the addition of a new tailblock rate for residential rates and the inclusion of environmental adders in marginal costs. OCEUR objects to the proposed increase in power factor requirements and recommends a reduced level. We address each issue separately.

ODOE's Inverted Rate Design. PGE's present residential rate tariff employs a two-block inverted rate structure. Customers pay one rate for the first 300 KWh per month, then pay a higher rate for all additional KWh used in that month. ODOE contends that this rate design does not correspond to LRIC and recommends a three-block rate structure. ODOE's proposal would retain the current initial block of 0 to 300 KWh per month, but change the second block to 300 to 2,300 KWh per month and add a third block, priced at LRIC, for use greater than 2,300 KWh per month. ODOE contends that this inverted rate design will help send proper price signals and promote energy conservation.

To support its proposed rate design, ODOE asserts that households that use over 2,300 KWh per month have more opportunities for conservation than households that use less electricity. ODOE fails to provide any studies to support that assertion, however. PGE's 1992 Integrated Resource Plan found that over 60 percent of potential savings were related to lighting, water heating, and appliances. Thus, all customers, regardless of their usage levels, have opportunities to conserve. Moreover, as noted by PGE, less than six percent of its residential customers use more than 2,300 KWh per month. With so few customers facing this higher tailblock rate, it is uncertain that ODOE's proposal will actually promote energy conservation and reduce inefficient electricity use. Given these uncertainties, and in the absence of an supporting empirical studies, we are unwilling to adopt ODOE's proposed rate structure in this proceeding.

ODOE's Inclusion of Environmental Externalities. ODOE also recommends the use of externality costs in designing residential rates. Specifically, ODOE recommends that LRIC should include a $10 per ton of carbon dioxide (CO_2) adder. ODOE contends that such an adder will account for the risk that carbon dioxide emissions will be taxed or otherwise internalized in the near future.

In UM 424, Order No. 93-695, the Commission adopted guidelines for the treatment of external environmental costs related to energy resources. Although this Commission decided that it was appropriate to consider external environmental costs in a utility's LCP, we recognized that our authority to impose such costs on a utility or its customers was limited by law. *Id.* at 2. Accordingly, we declined to determine whether to apply environmental externalities to rate design, and indicated that any decision doing so would require further examination of our authority and a full airing of views on the merits of including external costs and on the specific cost figures to be used. *Id.* at 16.

We are aware of numerous state, federal and international efforts to reduce CO_2 emissions. Uncertainties remain, however, whether future regulation will internalize the cost of CO_2 emissions by utilities. In light of questions regarding our authority to impose external environmental costs on a utility, and in the absence of a more complete record on this issue, we decline to adopt ODOE's recommendation to include a CO_2 adder in LRIC.

OCEUR's Opposition to Proposed Power Factor Requirements. Currently, PGE charges customers $0.50 for each kilovolt-ampere of reactive demand in excess of 60 percent of the KW billing demand. This occurs when the customer's power factor[11] drops below 85.7 percent. PGE and staff have stipulated to lowering the threshold level for its reactive demand charge from 60 percent of KW billing demand to 40 percent. Under that level, customers with power factors below 93 percent will be subject to the charge. OCEUR objects to the proposed increase in power factor requirement. OCEUR believes that raising the threshold from 85.7 to 93 percent would result in a too drastic rate increase for affected customers. It proposes the threshold be changed from 60 percent of KW billing to 50 percent. That proposal would result in a charge being imposed on customers with a power factor less that 89.4 percent.

We are not persuaded by OCEUR's argument and find the stipulated reduction to 40 percent of KW billing reasonable. We take official notice of staff's 1990 Research Report on Electric Energy Efficiency Opportunities in Oregon Industries.[12] In that report, staff concluded that the power factor threshold should be raised to 90 percent or higher to promote customer energy efficiency and reduce energy losses on the utility's distribution system. The stipulated proposal would accomplish that recommendation. Furthermore, while we acknowledge OCEUR's concerns regarding the extent of the increase, the stipulated power factor requirement is similar to that of other Northwest utilities, such as the BPA, whose power factor requirement is set at 95 percent, and Pacific Power & Light, whose power factor requirement is at 93 percent.

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[11] A low power factor may reflect poorly loaded motors and causes increased energy losses on a utility's distribution system.

[12] Pursuant to OAR 860-14-050(1), a party may explain or rebut the noticed fact within 15 days of notification.

PHASE II

Issues List

On September 15, 1994, staff filed a supplemental list of issues it identified for Phase II of this proceeding. As with staff's Phase I issues list, we use staff's numbering of Phase II issues in this section of the order. *See* Appendix F, Adjustment Summary, page 1, for a complete list of issues.

Stipulations

On November 15, 1994, PGE and staff submitted a stipulation intended to resolve rate of return and equity issuance cost issues. The stipulation is attached as Appendix E. The stipulation was supported by testimony of John Thornton, Jr., of staff and Joseph Hirko and Patrick Hager of PGE.

On February 27, 1995, PGE and staff submitted an additional stipulation intended to resolve Trojan balancing account issues. The stipulation is attached as Appendix D.

The stipulations and supporting testimony were entered into the record of this proceeding as evidence pursuant to OAR 860-14-085.

Evidentiary Hearing

During the week of January 9, 1995, Hearings Officers Ruth Crowley and Michael Grant held a Phase II evidentiary hearing in Salem, Oregon. Randy Childress, Melinda Horgan, and Rochelle Lessner, Attorneys at Law, appeared on behalf of PGE. Paul Graham and Michael Weirich, Assistant Attorneys General, appeared on behalf of staff. John Stephens, Attorney at Law, appeared on behalf of the Citizens' Utility Board (CUB). Geoffrey M. Kronick, Attorney at Law, appeared on behalf of the Bonneville Power Administration (BPA). John A. Kullberg, ratepayer, appeared on his own behalf.

Procedural Rulings

At the outset, we must address several procedural matters raised by URP in its Phase II brief. URP first asserts that the procedural history of this case has prejudiced the rights of the contested case participants, because the Hearings Officers issued a ruling on evidentiary matters the day before Phase II opening briefs were due. URP also argues procedural harm from the fact that the Hearings Officers faxed their ruling to Linda Williams without checking that she was there to receive the fax, rather than to Daniel Meek, URP's counsel of record.

We conclude that URP has not suffered prejudice because of the procedural history of this case. URP did not ask for an extension to mitigate any prejudice it might have experienced from the ruling. Nor does URP demonstrate how it was prejudiced. In fact, although the ruling struck some of URP's evidence, URP included argument about that evidence in its brief. URP's argument about the fax is disingenuous. Ms. Williams specifically requested the Hearings Division to fax her the ruling, because Mr. Meek was out of the country.

Second, URP alleges that its request to hold hearings in Portland, made at the January 6, 1995, prehearing conference for Phase II, was denied "without any findings why access to the hearings was being arbitrarily denied to the vast majority of affected customers." That motion had already been made and denied almost a year earlier, by ruling dated January 19, 1994. It was not necessary to repeat the grounds for a ruling that had already been made.

URP further argues that refusal to hold hearings in Multnomah County violates the equal protection clause of the fourteenth amendment and the privileges and immunities clause of the Oregon constitution. We have reviewed URP's arguments and are not persuaded by them.

Based on the record in these proceedings, we make the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Stipulated Issues

The Phase II stipulations submitted by PGE and staff cover three issues: S-0: Rate of Return; S-33: Equity Issuance Costs; and an unnumbered issue relating to a Trojan Cost Balancing Account. The parties have agreed to: (1) a stipulated rate of return of 9.51 percent for 1995 and 9.60 percent for 1996; (2) a stipulated common equity issuance cost of $1.75 million for both 1995 and 1996; and (3) a stipulated method to vary the amortization of the Trojan investment to take into account the actual revenue collected from ratepayers as a result of this order.

We have reviewed the stipulations and testimony and find the agreement on these three issues reasonable. Accordingly, the stipulations, attached as Appendices E and D, are adopted.

Contested Issues

The contested Phase II issues relate to PGE's Trojan Nuclear Power Plant (Trojan). The most significant of these issues concerns the ratemaking treatment of PGE's remaining investment in Trojan: S-50: Remove Additional Fixed Costs - Net

Benefits Analysis. Other issues include: S-45: Trojan Overtime; S-46: Trojan Investment Reclassification; S-47: Added Trojan Salvage Recoveries; S-48: Trojan Decommissioning; S-49: Remove Plugging, Sleeving, Analysis and Spare Nuclear Reactor Coolant Pump Motor; S-51: Remove Trojan Power Cost Deferral; S-52: Trojan Income Tax Write-off; S-53: and Trojan Intangible Asset Reclassification.

We will begin with a brief history of Trojan and review of the legal framework of this case, including a discussion of the assumed facts and conditions for recovery set forth in DR 10, Order No. 93-1117. That will be followed by a review of staff's net benefits analysis (Issue S-50), succeeded by the other contested issues in numerical order.

History of Trojan

Trojan began commercial operation in 1976. It was licensed to operate until 2011. Trojan was a single-unit 1200 MW plant, the largest in the Northwest at the time of its construction. PGE owns 67.5 percent of the plant. BPA owns 30 percent under net billing agreements with the Eugene Water and Electric Board and several other publicly owned utilities. PacifiCorp owns 2.5 percent.

Trojan was a pressurized water reactor (PWR) nuclear generating facility. PWRs rely on steam generators to heat and cool the water that powers the generating turbine. Steam generators are large pressure vessels that transfer heat from the water in the reactor coolant system (primary system) to the water in the turbine system (secondary system). The water in the primary system is pressurized to keep it from boiling. The heat transfer occurs through the walls of thousands of tubes in the steam generator. The primary system water flows inside the tubes and the secondary system water flows around the outside of the tubes. The heat transferred to the water on the secondary side of the steam generator causes it to boil, producing steam.

The steam produced in the steam generators flows through piping to the turbine generator, where it passes through and drives the turbine. The steam passes through a condenser, where it is turned to water, and the water flows through feedwater heaters and back into the steam generators.

The steam generators, particularly the generator tubes, contain the primary system radioactive water and prevent the release of radioactive water to the secondary system. Trojan contained four steam generators, each with 3,388 tubes, which PGE purchased from Westinghouse in 1968. PGE is currently engaged in a civil suit against Westinghouse with respect to the steam generators, which degraded badly starting in 1989. By 1991, PGE had plugged or sleeved (permanently attach another tube inside a degraded tube) more than 25 percent of its steam generator tubes.

During its least-cost planning process in 1992, PGE weighed Trojan's continued viability. Among other things, PGE considered the cost of replacing the four steam generators in 1996, the loss of generation that would occur until they were replaced, and the replacement power costs such a loss would entail. In its 1992 Least-Cost Plan (LCP), PGE decided to close Trojan in 1996. As further steam generator degradation became apparent, however, PGE realized that closing Trojan immediately was its least-cost option. On January 4, 1993, the company announced the permanent shutdown of Trojan. PGE's February 1993 Update to its LCP shows its analysis.[13]

Applicable Law

As the petitioner in this rate case, PGE has the burden of proof on all issues. ORS 757.210 provides that, in a rate case, "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable." The requirement applies to PGE's entire case, including the allocation of Trojan costs.

Further, ORS 757.140(2) provides:

> In the following cases the commission may allow in rates, directly or indirectly, amounts on the utility's books of account which the commission finds represent undepreciated investment in a utility plant, including that which has been retired from service:
>
> * * * * *
>
> (b) When the commission finds that the retirement is in the public interest.

This statute requires that PGE make an affirmative showing that retirement of Trojan was in the public interest in order to include Trojan costs in rates.

The Commission established the legal framework for the Trojan issues in this case in DR 10, Order No. 93-1117. In that order, the Commission adopted the reasoning of the Attorney General's Opinion Letter OP-6454, which advised that the Commission may allow a utility to recover undepreciated investment in retired plant and a return on that investment if the Commission finds such recovery to be in the public interest under ORS 757.140(2)(b).

In their Phase II briefs, CUB, URP, and the Public Power Council argue against our conclusions in DR 10. They contend that ORS 757.355 bars recovery of and return on undepreciated investment in retired plant.[14] We fully addressed that argument and

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[13] At the Phase II hearing, the Hearings Officers took official notice of both PGE's 1992 LCP and its February 1993 Update. The LCP was acknowledged by the Commission in Order No. 93-803 (LC 7).
[14] ORS 757.355 provides:

rejected it in our resolution of DR 10. Our decision was appealed to and affirmed by the Marion County Circuit Court, and is currently pending before the Oregon Court of Appeals. We will not revisit that issue here.

Standard for Recovery of Undepreciated Investment

The Concept of Net Benefits. In Order No. 93-1117, we concluded that one way a utility may show that a plant closure is in the public interest is if there is a "net benefit" from early closure of the plant. In other words, if the costs of continued operation of the plant are greater than the costs associated with retiring the plant plus the expected long-term costs of replacing the plant's output, there is a net benefit to closure.

The DR 10 Requirements. The language of ORS 757.140 is discretionary: the Commission may allow the utility to recover undepreciated investment in rates. In Order No. 93-1117, we set forth the conditions under which we would favor allowing PGE to recover some or all of its undepreciated investment in Trojan and a return on that investment. First, we assumed six facts:

Assumed Facts:

1. Trojan began commercial operation in 1976. The Commission approved the inclusion in rate base of PGE's investment in Trojan in Order No. 75-832 as construction work in progress and in Order No. 76-601 as completed plant.

2. PGE has made additional investments in Trojan, most of which the Commission has approved for inclusion in rate base through 1991, the test year approved in Order No. 91-186 (UE 79).

3. Since January 1, 1992, PGE has made additional investments in Trojan. The investments were prudent and necessary for the provision of utility service.

4. PGE has depreciated and is presently depreciating its investment in Trojan over a useful life assumed to end in 2011. Since 1976, the Commission has set PGE's prices to include amounts for annual depreciation expense and a return on the undepreciated balance of PGE's Trojan investment.

No public utility shall, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates which are derived from a rate base which includes within it any construction, building, installation or real or personal property not presently used for providing utility service to that customer.

5. PGE has accrued, and is presently accruing, and depositing in an external trust, funds to decommission Trojan based on a schedule of charges designed to produce the estimated amount necessary for decommissioning in 2011. Since 1976, the Commission has set PGE's prices to include amounts for future decommissioning of the plant.

6. Closing Trojan permanently in January 1993 was PGE's least-cost option.

Disposition:

PGE and staff agree that PGE has met its burden of proof with respect to five of the six assumed facts, including the fact that permanent closure of Trojan was PGE's least-cost option. They disagree on assumed Fact 3.

Facts 1 and 2. We find that Fact 1 is verified by Order Nos. 75-832 and 76-601, while Fact 2 is verified by Order No. 91-186.

Fact 3. We find that certain of PGE's post-1991 investments in Trojan were not prudent. We disallow costs for steam generator plugging, sleeving, and analysis and a spare reactor coolant pump motor. *See* discussion at S-49 below.

Fact 4. In Order No. 76-601, the Commission included the investment in Trojan in plant in service. The depreciation rates to be used on that investment were specified in a PGE memo dated January 8, 1976. Trojan has been included in plant in service in several general rate orders in the intervening years, the most recent being order No. 91-186. We find that this verifies Fact 4.

Fact 5. We conclude that Fact 5 is verified. In Order No. 76-601, which included Trojan in plant in service, the depreciation rates in use included a negative net salvage percentage to cover the cost of removing the plant from service. This percentage was not identified as decommissioning at that time, nor was a specific amount of money identified as a decommissioning cost. However, negative net salvage and a decommissioning accrual are conceptually equivalent (see discussion below, S-48: Trojan Decommissioning).

In Order No. 80-612, the Commission adopted a decommissioning study prepared by Nuclear Energy Services, Inc. That study estimated the cost of removing Trojan from service and established a decommissioning fund. PGE was to make regular accruals to that internal sinking fund. The fund was to finance decommissioning when the plant was removed from service. The internal sinking fund was maintained until Order No. 91-186 (UE 79). In that order, the Commission approved a new decommissioning plan; approved the cost estimate associated with the plan; provided for an external decommissioning fund to be established and managed by an independent trustee; and provided for annual contributions to be made to the fund, which would grow to an amount equal to the decommissioning cost estimate at the time of decommissioning in 2011. PGE is currently depositing the amount prescribed in Order No. 91-186 in the external trust fund.

Fact 6. PGE relies on its LCP to prove Fact 6. In the November 1992 Plan, PGE compared the costs of three Trojan options: continued operation through 2011, phase-out in 1996, when the steam generators would otherwise need to be replaced, and immediate closure with the plant kept on standby for two years. PGE compared these three options over a range of assumptions about future Trojan operation and the cost of replacement resources. In its LCP, PGE concluded that phase-out was the least-cost option. In its February 1993 Update, it compared phase-out with immediate closure and not keeping the plant on standby. Based on the analysis in its Update, PGE concluded that closing Trojan permanently in January 1993 was its least-cost option.

Staff agrees that the LCP proves Fact 6. Staff reviewed PGE's model design, Trojan cost and operating assumptions, and replacement cost assumptions and determined that PGE's analysis of its least-cost option was correct. Staff's review showed that PGE used two approaches to model the Trojan cost options. The probabilistic model used probability distributions on values for key inputs to generate a distribution of outcomes, measured in terms of the present value of avoidable costs. PGE used a range of values for Trojan capacity factor, fixed operations and maintenance costs, and capital additions. PGE used the Northwest Power Planning Council's (NWPPC) regional planning model as one basis for replacement power costs.

PGE also used a scenario approach, in which costs were derived from specific input values. The company combined different assumptions about loads, gas prices, nuclear and emission externalities, and Trojan operations and costs. Replacement costs in the scenario approach were based on resources available to PGE instead of the regional portfolio developed in the NWPPC model. In its Update, PGE changed its assumptions about Trojan costs and operations and about replacement power costs in 1993-1996. It examined scenarios based on different assumptions for forced outages, plant repair costs, and replacement costs.

After reviewing PGE's LCP and staff's evaluation, we conclude that PGE has proved Fact 6.

Although PGE has not proven Fact 3, PGE has substantially complied with the requirement that it prove all six facts in a rate case. We have the discretion to disallow those costs found to be imprudent and to allow a recovery of some or all of the undepreciated Trojan investment.

Conditions on Recovery:

After setting out the six assumed facts that PGE must prove, we listed six conditions that PGE must meet in order for the Commission to allow it to recover some or all of its undepreciated investment in Trojan:

1. PGE's questions are based on six assumed facts regarding Trojan. PGE must prove all six facts in a rate case or similar forum.

2. PGE must show that it has made a diligent effort to reduce other company costs to offset the inclusion of any Trojan costs in rates. For instance, PGE may show that the Trojan closure decision is consistent with least-cost planning criteria over the longer term, but that near-term rates may be higher as a result of the decision. PGE must show that it has made reasonable efforts to keep costs down, especially discretionary costs, before asking customers to pay higher bills in the near term to support its closure decision.

3. PGE must show why it is reasonable to allow 100 percent recovery of Trojan-related costs in rates. Issues regarding cost recovery are complex and significant. After review, the Commission may decide that PGE is entitled to full recovery of unrecovered plant costs, or it may determine that some cost sharing should occur between customers and investors.

4. PGE must show that it has aggressively attempted to maximize the salvage value of the Trojan facility. If customers are asked to bear some unrecovered costs, PGE must show it is making every reasonable effort to mitigate those costs.

5. PGE must report within 30 days any settlement or award related to replacement power costs, unamortized investment, or any other costs of owning or operating the Trojan plant.

6. PGE must provide satisfactory evidence with regard to any other matter the Commission deems relevant to this issue in a rate proceeding.

Disposition:

The first condition, proving the assumed facts, is addressed immediately above. As to cost reduction, the second condition, staff concluded that PGE had made good efforts to reduce company costs to offset Trojan cost recovery. However, staff compared PGE's administrative and general (A&G) costs with those of Puget Sound Power and Light, a comparable utility in terms of size and service area.[15] PGE's costs were materially higher for 1989 through 1993, and staff concluded that PGE could find ways to reduce A&G costs still more.

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[15] A&G costs are largely discretionary. Discretionary costs include operating and maintenance expense accounts (company labor and benefits, contract labor, office supplies and expenses, insurances, transportation, and outside services). They exclude Trojan O&M, amortization of energy efficiency balances, uncollectible accounts, regulatory expenses, and rents.

We agree with staff that it is possible for PGE to be more aggressive in its efforts to reduce discretionary costs. Trojan's closure is having and will continue to have an adverse effect on customer rates in the near term. Amortization of replacement power cost deferrals will add approximately $150 million to PGE's revenue requirement from 1992 through completion of amortization. While PGE has made some efforts at cost reduction, we believe that the company can and should do more to mitigate the adverse rate effects discussed above. Accordingly, PGE's rates should recognize a reduction of 1 percent in discretionary costs over and above that approved in Phase I of this Order. We find this a reasonable allowance for discretionary costs. We decline to identify particular program areas that may be susceptible to reassessment or to impose specific cost reductions. These discretionary costs are best managed by the company.

We acknowledge that these reductions will require difficult choices. Nonetheless, we expect the company to make those choices if it is asking customers to pay higher bills in the near term to support PGE's closure decision. This reduction in discretionary costs reduces PGE's revenue requirement by $1.631 million in 1995 and $1.687 million in 1996.

The third of the DR 10 conditions merely puts forth in condensed form PGE's entire Phase II case. We address this condition below as Issue S-50: Remove Additional Fixed Costs - Net Benefits Analysis. The fourth condition, dealing with salvage value, is also addressed below under Issue S-47, Added Trojan Salvage Recoveries. The fifth condition, requiring PGE to report any settlement or award, is not yet ripe. We continue to impose this requirement on PGE. We did not impose any additional requirements pursuant to the sixth condition.

The Net Benefits Test

As Order No. 93-1117 set out, the first step in determining whether closing Trojan was in the public interest under ORS 757.140(2) is to ask whether there is a net benefit from closure. In its initial filing in November 1993, PGE relied on its least-cost planning analysis to justify its position that it should receive 100 percent recovery of Trojan costs. PGE maintains that closing Trojan was its least-cost option.

Staff agrees that closing Trojan was PGE's least-cost option. Staff argues, however, that an LCP analysis does not serve to determine whether an action is in the public interest for purposes of allocating undepreciated Trojan investment. The LCP takes the plant as it exists at the time of LCP review. It does not question whether actual costs *should* have been incurred. It then projects costs based on the plant's actual operation out over the time until Trojan's license would have expired. Under an LCP, a poorly run plant may be so expensive to operate that closure would be the least-cost option. That outcome is appropriate and desirable in the framework of the least-cost planning process.

Staff contends, however, that the LCP is not the appropriate tool to determine who should pay for the remaining undepreciated investment in a prematurely retired plant. Using the LCP to allocate remaining undepreciated costs could allow a utility to shift the capital or operating costs of its own imprudence to ratepayers. If PGE managed Trojan imprudently and the costs and capacity factor used to model continued Trojan operation were adversely affected as a result, the apparent benefit of closing the plant would be overstated.

Staff argues that the net benefits analysis is the appropriate vehicle for deciding how to allocate the remaining Trojan costs. A net benefits analysis is not used to decide whether a plant should be kept in operation. Instead, it compares the *allowable* projected costs of continuing to operate a plant with the allowable costs of closure. Allowable costs are those costs the Commission would deem reasonable and allow PGE to collect from its ratepayers.

Consequently, staff performed a net benefits analysis of PGE's operation of Trojan. Like the LCP, the net benefits analysis projected the costs of operating Trojan out to 2011, the year in which the plant would have closed. The starting point for staff's study was 1995, the first test year in this proceeding. Staff's review differed from an LCP analysis in two significant ways. First, it asked what projected costs are allowable, and disallowed those costs that it considered not reasonable to impose on ratepayers. Second, it used updated information, while the LCP used information as of the time the decision was made to close the plant.[16]

PGE argues that it is bad policy for the Commission to modify the outcome of the LCP. The utility notes that its decision to close Trojan was reached in the least-cost planning process and acknowledged by this Commission. Actions pursuant to an acknowledged LCP are in the public interest, PGE argues. The utility maintains that it must be able to rely on cost recovery for prudent actions, such as taking a facility out of service where that is the least-cost option. If not, PGE contends, utilities will have no incentive to discontinue operation of such facilities.

Disposition:

We agree with staff that the net benefits analysis is the appropriate vehicle for determining whether closure of Trojan was in the public interest for purposes of determining recovery of undepreciated investment. PGE argues that failure to grant recovery for least-cost actions could lead to utilities operating plants that should be closed. The Commission responds that if an LCP dictates closure of a plant and a

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[16] The net benefits analysis and the LCP differ in a further particular also. Under the net benefits analysis, sunk investment cost is added to the cost of each option. An LCP focuses on the avoidable or deferrable costs of a resource option. The net benefit treatment of sunk investment cost does not, however, change the difference between the costs of any two options, so it does not play a role in staff's assessment of net benefits.

company continues to operate it, the company may not be allowed the full cost of operating the plant in rates. Thus a utility would have no incentive to keep a poorly run, expensive plant on line. Staff's net benefits methodology will be discussed and evaluated immediately below (S-50: Remove Additional Fixed Costs - Net Benefits Analysis). We also agree that the relevant study period for the net benefits analysis is 1995-2011.

Post-1991 Capital Expenditures

In addition to its net benefits analysis, staff reviewed PGE's post-1991 Trojan-related capital expenditures. Those expenditures have never been in PGE's rate base, because they were incurred after PGE's last general rate case, UE 79. These expenditures include all post-1991 steam generator costs (deferred or capitalized plugging, sleeving, and analysis activities), which amount to about $14.9 million, and a spare reactor coolant pump motor, purchased in March 1991 for $2.2 million and never used.

ORS 757.140 does not apply to these expenditures. They are evaluated simply as capital expenditures proposed for rate base treatment and excluded for reasons discussed under Issue S-49 below.

S-50: Remove Additional Fixed Costs - Net Benefits Analysis

As stated, a net benefit exists when the dollars saved by prematurely retiring plant are greater than the costs associated with building new plant. Here, staff made that determination with regard to the early retirement of Trojan by taking the difference between (1) the expected allowable long-term costs of continued operation of Trojan and (2) the costs associated with closing the plant plus expected long-term costs of replacing its output. Stated in algebraic terms, a net benefit exists if:

$$(X + Y) > (X + Z)$$

where: X = Unamortized investment in Trojan
Y = Expected allowable long-term costs of continued Trojan operation
Z = Replacement resource costs

Calculating the long-term costs of Trojan's operation and replacement resources is a difficult matter. Staff's net benefits analysis is necessarily detailed and complex. Difficulties arise in quantifying the long-term effects of a series of past choices and projecting them out 17 years. Relatively small changes in some key allowable cost inputs adjustments produce a large change in results. This sensitivity is a result of the fact that Trojan closed 19 years prior to the expiration of its 35-year license life.

To explain the net benefits analysis, we will describe briefly the numerous steps involved in staff's review and summarize staff's findings. PGE and, to a lesser extent, CUB, recommend a number of changes to staff's analysis. We address those arguments as they arise, and resolve disputed issues in the course of our discussion.

1. Least-Cost Plan (LCP) as a Starting Point

As noted above, staff concluded that PGE's least cost planning analysis was not appropriate for determining the net benefits of closing Trojan. However, staff determined that the company's LCP was a good starting point to establish both the long-term cost of replacing Trojan's output and the expected allowable long-term total capital and operating cost of the plant. For purposes of the net benefits analysis, however, staff found that it had to resolve two basic problems with the LCP before beginning its review. First, because PGE prepared the LCP in two parts--the November 1992 Plan and the 1993 Update--staff first had to combine and reconcile the results. Second, because the LCP relied on different planning "scenarios," staff had to identify and select the scenarios most compatible with a net benefits review.

Staff began its analysis by choosing the results of: (1) Case 1b in the 1992 Plan, which showed that continued operation of Trojan until 2011 would cost $110 million more than phase-out in 1996; and (2) Scenario 3 in the Update, which concluded that phase-out would cost $78 million more than immediate shutdown. Staff then combined the results of the two planning scenarios to obtain a beginning estimate of the higher cost of continued operation of Trojan relative to immediate shutdown, i.e., $188 million. Staff further determined that two additional adjustments were necessary to account for different assumptions about phase-out in Case 1b and Scenario 3. Staff removed additional O&M and A&G costs that PGE included in the 1993 Update. Staff also adjusted for capacity factor differences in 1993-1995 as part of the first step in its overall capacity factor adjustment

PGE raises two arguments relating to staff's use of the LCP as a starting point for its net benefits analysis. First, PGE challenges staff's reliance on Case 1b from the 1992 Plan. It believes that the LCP's probabilistic analysis, not the scenario approach, provides a more complete view of all potential outcomes and should be used in staff's net benefits test. Using the $168 million expected net present value of phase-out over continued operation determined from the probabilistic analysis instead of the $110 million figure from Case 1b would reduce the negative net benefit to about one-third of staff's estimate.

We are not persuaded by PGE's argument. As staff notes, the discrete input values used in Case 1b closely approximate the expected values of the probability distributions PGE constructed for the Trojan inputs. Moreover, Case 1b is based on replacement resources available to PGE, unlike the probabilistic analysis run with replacement costs derived from the Northwest Power Planning Council's regional model. Staff's use of Case 1b also allowed it to use the sensitivity analysis results reported by PGE for various Trojan and replacement cost inputs. For these reasons, we agree with staff that the Case 1b result, combined with Scenario 3, should be the starting point of the net benefits analysis.

PGE next contends that the least-cost planning results should be modified to reflect the use of different nuclear fuel assumptions in the 1992 Plan and the Update. We find PGE's proposed adjustment reasonable and accept it. This adjustment is further addressed below as part of our resolution of Issue S-50.

2. Adjustments to Update the LCP with Current Information

Staff next revised the least-cost planning results to incorporate currently available information. Staff made a total of four such adjustments. Three of the adjustments are not disputed: (1) to reflect lower transition costs experienced and projected by PGE for 1993-1995; (2) to recognize lower replacement power costs in 1993-1995, based on PGE's recent experience and current projections; and (3) to show lower gas prices, using the gas price forecast it sponsored in Phase I of this proceeding.

Staff's fourth adjustment revised the LCP to incorporate new information about the capital costs of long-run replacement resources. Staff modified the LCP to reflect (1) lower estimates of the installed cost of new gas-fired resources; and (2) a 100 MW reduction in PGE's reserve margin requirement. PGE challenges both elements of this adjustment.

First, PGE contends that staff's analysis overstates the costs of a new gas-fired resource by not correcting an error in the carrying charges[17] used in the 1992 Plan. We find PGE's proposed adjustment reasonable and adopt it. We address this adjustment below as part of our resolution of Issue S-50.

Second, PGE contends that the net benefits analysis should assume a 145 MW reduction in its planning reserve margin requirement, rather than staff's proposed 100 MW reduction. PGE contends that, in addition to a 100 MW reduction in its forced outage reserve requirements brought about by Trojan's closure, its operating reserve needs have also decreased by approximately 45 MW as a result of replacement power purchases. Because these power purchases carry their own operating reserves, PGE contends that staff's adjustment should reflect this additional reduction in the company's operating reserve requirements.

We find that staff's 100 MW reduction is more appropriate for a net benefits analysis. Although PGE claims to have experienced a reduction in its operating reserves, it admitted that it has not completed studies required to quantify any effect of closing Trojan on its operating reserve requirements. Furthermore, as staff points out, the replacement power purchases that purportedly reduce PGE's operating reserves are short-

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[17] Carrying charges are factors used to convert capital costs into annual revenue requirements.

run replacements for Trojan. When long-run resources become operational, PGE's required operating reserves will increase.

3. Adjustment to LCP for 1995-2011 Study Period

To reflect a 1995-2011 study period, staff adjusted the LCP to remove the costs of continued Trojan operation and immediate shutdown for 1993-1994. Because the costs of continued operation are less than the costs of shutdown in 1993-1994, the adjustment increases the net benefits of closing Trojan.

4. Adjustments to LCP to Reflect Allowable Costs

As previously stated, a net benefits analysis compares the allowable costs of continuing to operate a plant to the costs of closure. To help determine the correct amount of present and future allowable costs, staff retained the services of Theodore Barry and Associates (TBA), an independent firm specializing in providing consulting services pertaining to the energy and telecommunications industries. TBA has performed many nuclear plant reviews, management assessments, and audits, and it has testified in numerous power plant rate case proceedings. We find TBA qualified to advise staff in its net benefits review.

TBA evaluated the reasonableness of PGE's operation and management of Trojan from its initial commercial operation in 1976 through current delicensing and decommissioning activities. TBA described its standard of review as follows:

> Whether PGE personnel, in managing activities associated with operations, maintenance, outages, engineering, modifications, quality assurance, and other activities at Trojan, made the decisions and took the actions, including the allocation of resources and the implementation of management and control systems, that a reasonable, experienced and competent manager of a licensed nuclear power facility would be expected to take, to operate and maintain the Trojan Nuclear Plant in a safe, reliable and cost effective manner. Where it appeared that such actions had possibly not been taken, and systems not implemented, we looked to see whether PGE management personnel took reasonable and timely actions to correct the situation.
>
> TBA focused on those factors that represented the controllable elements of plant-related activities, in the context of information that was known, or was available to, and should have been known by PGE at the time. We were careful not to judge PGE's actions based on the results of its actions; rather we ascertained whether PGE made a reasonable choice from among the

> alternatives that were, or should have been available, i.e., we were careful to avoid the use of hindsight in our assessments.
>
> In addition, we recognized that one or more courses of action can be deemed reasonable for a given set of circumstances, and did not limit our determination of reasonableness to only the best course of action, but considered the applicable range of reasonable actions in making our assessments.

TBA examined key areas of PGE's management and operation of Trojan to determine its reasonableness as well as its impact on key inputs for staff's net benefits analysis. Generally, TBA's evaluation can be divided into three major areas: (1) comparative performance analysis; (2) review of management issues; and (3) analysis of steam generator issues. TBA's evaluation and findings in these three areas are addressed separately, followed by a discussion of TBA's quantification of its findings for the net benefits analysis.

A. TBA's Comparative Performance Analysis

TBA compared Trojan's performance to that of other nuclear plants to help quantify the cumulative impact of the numerous controllable and uncontrollable factors on the plant's performance in the context of the performance achieved by comparable plants. TBA included several factors in its comparative analysis, including capacity factors,[18] availability factors,[19] O&M expenditures, Nuclear Regulatory Commission (NRC) Systematic Assessment of Licensee Performance (SALP) Report ratings, NRC Maintenance Team Inspection (MTI) Report ratings, and planned refueling outage duration.

Using these factors, TBA compared Trojan's performance to: (1) other single-unit nuclear plants; (2) other single-unit nuclear plants with pressurized water reactor (PWR) nuclear supply systems; (3) nuclear plants that began commercial operation between 1971 and 1981; and (4) all domestic nuclear plants. TBA selected those comparison groups to provide the maximum number of comparable nuclear plants for each parameter and include the plants with the characteristics most suitable for comparative purposes. In each comparison, TBA attempted to use as large a comparison group as possible in order to avoid skewing the data presented in the comparisons. At the same time, TBA was careful to exclude certain plants when the use of all nuclear plants would have been unfair to PGE. For instance, TBA excluded multiple-unit nuclear plants from O&M cost comparisons, because they typically have a lower O&M than single-unit

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[18] Capacity factor is defined as the ratio of actual generation to maximum possible generation, based on the rating of the unit, expressed as a percentage.

[19] Availability factor is defined as the ratio, expressed as a percentage, of the total amount of generation a plant could have produced, without discretionary shutdowns or power outage reductions, to the maximum possible generation a plant could have produced without any outages, discretionary or not.

plants such as Trojan. These comparison groups typically included from 26 to 40 nuclear units out of a total of approximately 100 units currently operating in the United States.

After its review, TBA determined that Trojan's lifetime performance on a total O&M cost/MWh generated basis was good, compared to plants that faced similar regulatory and management challenges. TBA further determined, however, that the favorable cost comparison was largely due to Trojan's relatively low O&M costs for most years prior to 1987, which compensated for the plant's relatively poor capacity factor performance. O&M costs increased significantly beginning in 1987, and TBA concluded that Trojan did not compare favorably to other single-unit nuclear plants in 1993, the year PGE decided to close Trojan.

TBA also drew several conclusions regarding specific factors identified above to be used in its analysis. Stated briefly, TBA found that:

- Trojan's lifetime capacity and availability factors were significantly lower than the same factors for all domestic nuclear power plants through 1992.

- Trojan had an economy of scale advantage over smaller single-unit plants.

- Trojan performed favorably over its life on a nonfuel O&M cost/MWh generated basis, but significant O&M cost increases in 1987 and thereafter were an important factor in PGE's decision to close Trojan.

- Trojan's low average capacity factor, together with its increasing O&M costs, caused the plant to be more costly in the early 1990s than the average for other single-unit plants.

- PGE's SALP scores deteriorated from the early 1980s through the early 1990s.

- Trojan's MTI performance was in the lowest (worst) quartile of plants reviewed, suggesting that PGE did not pay appropriate attention to Trojan maintenance activities.

- Trojan's outage performance had a negative impact on capacity factor.

PGE disputes the validity of TBA's comparative analysis. It contends that TBA's findings are suspect for several reasons, including: (1) biased and improper comparison group selection; (2) biased and improper time period selection; and (3) incomplete data selection. PGE provides its own comparative performance analysis, which it believes establishes that Trojan cost performance throughout the period from

1976 through 1992 was exceptional as compared to a cross section of subgroups of nuclear plants.

After a review of both comparative analyses, we find TBA's study more reliable to help quantify the impact of numerous factors on Trojan's performance. TBA's conclusions are well reasoned and based on the most complete and appropriate information. We do not find PGE's comparative analysis persuasive and, for the following reasons, give it little weight. First, PGE's conclusions are based on a comparison of average performance over the life of Trojan and other nuclear plants. The use of lifetime performance averages, however, inappropriately masks Trojan's declining performance from 1987 through 1992, as well as industry trends in outage durations. Moreover, PGE did not base its LCP inputs on Trojan's lifetime average performance, but rather on Trojan's performance immediately prior to the formulation of the LCP.

Second, PGE inappropriately compared Trojan's performance to small subsets of plants that masked the impact of Trojan's regulatory compliance problems on its performance. For example, for its most comparable group of plants, PGE used selection criteria that resulted in a comparison group of only five other plants, many of which had poor performance characteristics. Similarly, PGE limited its comparison group for capacity factor and availability factor to 12 plants, eight of which were on the NRC's Watch List of Troubled Plants. We are more persuaded by the comparative analysis performed by TBA, which appropriately used minimum selection criteria to produce a large data set to dampen the effects of the best and worst performing plants, as well as the effects of individual plant performance anomalies.

We acknowledge that PGE made two comparisons that TBA did not -- comparisons on the basis of revenue requirements and capital expenditures. However, revenue requirements are heavily influenced by historical factors, such as initial capitalization and subsequent capital additions. These factors are generally not as controllable by management as other cost components, such as O&M. Furthermore, PGE inappropriately assumed an identical return on book value for all nuclear plants. To adopt that assumption, PGE erroneously assumes an identical capital structure for all nuclear plants as well as equivalent authorized rates of return on each category of capital fund. PGE made additional errors that cast doubt on the reliability of its comparisons. For example, PGE compared initial and total nuclear plant capitalization costs after inflating to 1993 dollars, when annual revenue requirements are based on historical costs.

Finally, PGE criticizes TBA's use of SALP scores. The NRC generates a SALP report approximately once a year for each licensee. For the functional areas reviewed, the NRC assigns a numerical rating of 1, 2, or 3, with 1 being the highest rating and 3 the lowest. PGE argues that TBA's use of SALP scores to define reasonable management performance is improper. We agree that a determination of imprudence should not be based solely on a licensee's SALP score. Nonetheless, TBA properly used SALP scores to identify areas warranting further investigation, such as quality assurance, engineering management, and other areas addressed below.

B. TBA Review of PGE Management

TBA next examined PGE's management of the Trojan plant. Based on the comparative performance analysis and a preliminary review of Trojan documentation, TBA identified and examined several areas it believed had the greatest impact on Trojan's performance, particularly during the years immediately prior to PGE's decision to close the plant. The areas reviewed by TBA included PGE's quality assurance, engineering management, operations management, maintenance management, outage management, and regulatory compliance performance.

TBA's review found several areas where PGE's performance was good or exceptional. TBA found that Trojan placed twelfth among thirty-nine plants on the basis of lifetime O&M costs/MWh generated. TBA characterized PGE's overall emergency preparedness as good, noting that Trojan was one of the first plants to have a public warning system. TBA also rated PGE's performance in nuclear fuel management, steam generator inspection and repair, and delicensing as excellent. With regard to nuclear fuel management, TBA found that Trojan's fuel costs since the mid-1980s were generally ranked among the lowest of all domestic PWR plants. It concluded that PGE's actions to address steam generator degradation, once it realized that serious problems existed, were extensive, timely, and appropriate. Finally, TBA noted that PGE's delicensing activities allowed it to reduce staffing at the plant more rapidly than anticipated and achieve significant costs savings.

TBA further concluded that PGE's operations management was generally good. Although PGE's operations management of Trojan deteriorated significantly from 1980 through 1984, TBA found that PGE was able to sustain improved performance into the 1990s. By the late 1980s, TBA believes that PGE's operations management was so good that it may have saved Trojan from being added to the NRC's Watch List of Troubled Plants.

TBA also found several areas where PGE's performance was poor or deficient, however. Those areas are as follows:

Quality Assurance: Quality assurance (QA) comprises all planned and systematic actions necessary to ensure that the plant and its components will perform satisfactorily in service. QA requirements are prescribed in Title 10 of the Code of Federal Regulations (CFR), Part 50, Appendix B, and are enforced by the NRC.

TBA found that PGE's QA program was either deficient or seriously deficient throughout most of Trojan's commercial operation. TBA determined that the root causes for the deficiencies were: (1) insufficient management involvement in the QA program direction and review; and (2) an inappropriate focus on administrative audits rather than performance audits. TBA concluded that, despite warnings and opportunities to improve QA performance, PGE did not make the necessary changes until the 1990s. TBA believes that these avoidable deficiencies had a noticeable impact on PGE's regulatory compliance and engineering and maintenance performance in the mid-to-late 1980s.

Engineering Management: The primary engineering activities associated with an operating nuclear plant include the design and engineering of plant modifications and additions; providing technical input regarding the operation of plant equipment, components and systems; providing technical support regarding the resolution of plant problems; providing technical input regarding plant licensing issues; and directing and coordinating activities regarding the nuclear fuel cycle.

TBA found that PGE's overall engineering and engineering management performance was significantly deficient. TBA determined that: (1) PGE's propensity to minimize the use of outside engineering firms, and to maintain relatively low salaries for permanent engineering personnel, required it to rely heavily on contractor personnel, which caused dissatisfaction among permanent employees and affected performance; (2) PGE's cost consciousness tended to limit opportunities for PGE's engineers to interface with others in the nuclear industry; (3) PGE's delay in moving engineers to the site limited their ability to become involved in plant-related activities; and (4) PGE's overall inability to effectively manage its engineering work force limited the effectiveness of its engineering support of plant activities. TBA concluded that the deficiencies were avoidable and severely affected PGE's regulatory compliance performance.

Maintenance management: Maintenance management comprises the management of the activities necessary to keep plant equipment, components, and systems in a state suitable for safe and reliable operation.

TBA found that PGE's overall maintenance performance deteriorated during the 1980s. TBA believes that these deficiencies contributed to PGE's overall declining performance in the mid-to-late 1980s and that the resulting cost impacts, while not as significant as in quality assurance and engineering, were avoidable.

Outage planning and management: Outage planning comprises the actions necessary, prior to an outage, to plan, schedule and prepare for outage activities in an efficient and timely manner. Outage management comprises the actions necessary to coordinate and perform the outage activities in an efficient and timely manner, including revising plans and schedules to accommodate changing conditions and emerging problems.

TBA found that Trojan's refueling outage performance was dismal starting in 1987. Among other things, TBA determined that Trojan's outages generally took significantly longer than planned. TBA concludes that the outage management deficiencies were avoidable and had a negative effect on Trojan's capacity factor.

Regulatory compliance: TBA examined PGE's recognition of and compliance with the regulatory requirements governing the engineering, design, operation, maintenance, and testing associated with Trojan's safety-related structures, systems, equipment and components. In its examination, TBA reviewed (1) the frequency of NRC-assessed violations at Trojan in the 1980s; (2) the impact of PGE's actions that were at the root of the violations; (3) the need to significantly improve PGE's performance on Trojan expenditures; and (4) the impact of all of the above factors on PGE's decision to close the plant prematurely.

TBA found that PGE's Trojan regulatory compliance was poor. This inadequacy, TBA determined, was caused by previously discussed management deficiencies, particularly in the areas of QA, engineering, operations management in the early 1980s, and maintenance management. TBA concluded that an important impact of PGE's poor regulatory compliance was increased O&M expenditures as the company attempted to "catch up" and improve performance. TBA noted that, during the period from 1986 to 1989, Trojan's nonfuel O&M expenditures increased from approximately $52 million to $102.3 million, an increase of almost 100 percent.

TBA also concluded that PGE ran a considerable risk in adopting a management strategy to minimize regulatory margin. The NRC defines minimum regulatory requirements for every aspect of nuclear operations. A nuclear plant's performance should exceed this minimum level to provide additional assurance that the plant operator will meet the minimum requirements. The level of performance above minimum regulatory requirements is called regulatory margin; the greater the margin, the greater assurance that the minimum requirements will be maintained. In order to maintain relatively low costs, PGE adopted a strategy of minimizing regulatory margin. TBA concluded, however, that the company's implementation of that strategy was seriously deficient. TBA found that PGE had failed to adopt appropriate criteria to guide its implementation activities, which prevented it from reacting appropriately to NRC feedback and concerns regarding its regulatory performance. TBA further found that the cumulative effect of these prior deficiencies made the implementation of corrective action in 1986 difficult, costly, and time consuming. TBA finally observed that, throughout the 1980s, the NRC assessed PGE with several Severity Level II and III violations and associated civil penalties as a result of the deficient regulatory compliance performance that resulted from its precarious strategy.

Summary: To summarize, TBA drew the following conclusions:

- Trojan was among the best performing nuclear plants in the early 1980s in terms of O&M cost/MWh generated and regulatory compliance.

- After 1982, Trojan's regulatory compliance began to deteriorate and, by 1987, Trojan's economic performance was declining due to significantly increased O&M costs with no offsetting improvement in capacity factors.

- By 1988, Trojan was among the worst nuclear plants.

- By 1992, Trojan had lost virtually all the prior cost advantage over other single-unit plants that it had achieved in the early 1980s through good management.

C. TBA's Analysis of the Steam Generator Issue

As a final area of its analysis, TBA examined numerous issues relating to the design, operation, and maintenance of the Trojan steam generators. TBA's review began with PGE's purchase of the steam generators from Westinghouse in 1968 and ran through PGE's decision to close Trojan in 1993.

TBA reviewed the steam generator design, PGE's purchase decision, and PGE's operation and care of the steam generators to determine, in part, how the equipment's degradation factored into the LCP and the net benefits analysis. TBA concluded that PGE acted prudently with regard to its steam generator degradation activities.

D. Quantification of Deficiencies for Net Benefits Analysis

In addition to its review of PGE's operation and management of Trojan, and partly in reliance on the findings from that investigation, TBA helped staff forecast certain key allowable costs of future Trojan operation. These three key components of the continued operation forecasts include: (1) O&M costs; (2) capacity factor; and (3) steam generator costs. In quantifying the impacts of PGE's management deficiencies, TBA applied a performance standard of what PGE could reasonably have achieved. TBA's quantification methodologies resulted in a range of values for the various inputs. The two extremes of each range are equally likely for the purpose of determining allowable costs. However, because the range reflects a prediction of costs that would have been allowed in future rate cases, only one value in the range would have been allowed and any amount above that would have been disallowed.

For the purposes of the net benefits analysis, staff used the midpoint of each range, because it represents the middle point between equally likely higher and lower values. Staff assumed a flat distribution, because it had no basis for concluding that any one point in the range was more likely than another. PGE challenges staff's use of midpoints, asserting that staff's methodology ignores other potentially acceptable values in the ranges of assumptions. We disagree. Staff supported its use of the midpoint values with a probabilistic analysis by: (1) assuming a uniform probability distribution over each range, i.e., assuming that all values in a range are equally probable and values outside the range have zero probability of occurring; (2) selecting a value from each range at random; (3) calculating the net benefit with the values selected; (4) repeating the input selection and the net benefit calculation many times; and (5) averaging the resulting net benefits estimates. Staff's analysis determined that the average expected net benefit is approximately the same as that determined by selecting the midpoint values. Furthermore, staff's approach is similar to the one PGE used in its least-cost planning analysis. PGE reported the expected value of the difference in costs between continued plant operation and phase-out from its probabilistic analysis, just as staff has done for net benefits.

As discussed above, TBA's review of PGE's operation of Trojan revealed management deficiencies that resulted in significant cost increases from 1987 to 1992. From those findings, TBA concluded that PGE's least-cost planning analysis forecasted significantly greater, and inappropriate, O&M costs, an inappropriately low capacity factor, and inappropriate costs related to steam generators. We address each issue separately.

O&M Costs and Escalation Rates: TBA considered three primary factors in determining a reasonable level of Trojan's 1993 O&M expenditures: (1) PGE's actual budget for Trojan's 1993 expenditures; (2) the impact of the steam generator issue on Trojan's 1993 O&M budget; and (3) the impact of PGE's management deficiencies, prior to and during 1992, on Trojan's O&M budget. On a related issue, TBA also calculated appropriate O&M cost escalation factors for use in staff's updated net benefits analysis.

In its cost calculation, TBA started with Trojan's 1993 nonfuel O&M budget of $115.8 million. It then reduced that figure by $5.3 million to account for avoidable steam generator inspection and repair costs. This left $110.5 million. TBA then reduced the $110.5 million O&M cost level by 5 to 10 percent. TBA concluded that this additional reduction was necessary to reflect a previous management cost advantage that PGE should have been able to maintain due to its management strategy of minimizing costs while attempting to minimize regulatory margin. TBA's result is an allowable 1993 nonfuel O&M range of $99.5 to $105.0 million. The midpoint of TBA's range, $102.3 million, is within a range for the average nonfuel O&M expenditure for single-unit plants in 1993, adjusted for Trojan's economy of scale and management strategy cost advantage.

With regard to O&M cost escalation factors, TBA looked at industry data for the period 1981 through 1993. Based on that historical industry data, as well as current regulatory reform initiatives and increased competitiveness in electricity markets, TBA believes a 0 percent real O&M escalation factor is appropriate for the period from the present through 1996, while an O&M projected real growth rate of 0 to 3 percent is appropriate for the period 1997 through 2011.

PGE challenges both of TBA's calculations. First, PGE contends that TBA's projection for Trojan's 1993 O&M expenditures is too low, asserting that TBA applied a standard of perfection in determining the input for the net benefits analysis. PGE contends that the proper standard of performance for quantifying the company's imprudence should be based on industry average performance, rather than the performance PGE could reasonably have achieved with its management strategy advantage and the economy of scale advantage inherent in a plant with Trojan's capacity. We disagree. In recognition of the fact that Trojan was located in a low-cost market, PGE adopted a management strategy that minimized costs while also attempting to minimize regulatory margin. TBA's quantification of PGE's imprudence, therefore, is appropriately based on PGE's failure to maintain its management strategy, while also recognizing that PGE's actual regulatory margin was inappropriate. In other words, TBA did not apply a standard of perfection, but rather an appropriate performance standard of what PGE could have reasonably achieved.

PGE also challenges TBA's inclusion of newer single-unit plants in its comparison group to verify the reasonableness of the results of its quantification of Trojan's 1993 nonfuel O&M expenditures. PGE contends that Trojan costs are more appropriately compared with those plants that began operation between 1971 and 1981. We find TBA's comparison group appropriate. Trojan's MW rating made it the largest single-unit plant placed into operation prior to 1982. Trojan's economy of scale advantage, therefore, can and should be measured against the average of all single-unit plants. Similarly, PGE's management advantage was a function of economics, which relates to all single-unit plants, not merely a particular vintage of plant.

PGE further argues that Trojan's 1993 budget is not appropriate to use as a starting point for determining the nonfuel O&M cost input, because PGE had already made a decision to phase out the plant in 1996 and had begun to cut back on programs and costs. However, PGE's 1993 budget was approximately $11 million greater than its actual 1992 nonfuel O&M expenditures, a significantly greater increase than the average nonfuel O&M costs increases for other single-unit plants for that period. Moreover, PGE identified a reduction in its 1993 budget of only $2.2 million for programs that were to be either scaled back or eliminated due to its decision to phase out the plant in 1996.

With regard to TBA's O&M escalation factors, PGE claims that O&M escalation should be three percent real from 1993 forward, rather than TBA's proposed 0 percent real until 1997 and a range of 0 to 3 percent thereafter. However, TBA reviewed the nuclear industry's real nonfuel O&M per KW for 1989-1993 and found that it declined by an average of 0.53 percent per year. This fact was partially anticipated by PGE in its 1992 Plan, in which PGE stated:

> In addition, hindsight now shows that increased regulatory activity following Three Mile Island (TMI) caused many of the historical increases above inflation in fixed O&M and capital costs. The industry has essentially completed the TMI-related work, and industry data indicates that recent nuclear O&M expenditures have leveled and may possibly indicate a decreasing trend.

Moreover, TBA persuasively argues that this downward trend is sustainable and may even intensify because of: (1) industry-wide efforts to reduce regulatory costs; and

(2) increasing competition in the electric utility industry. For these reasons, we find TBA's 1993 O&M cost estimates and O&M escalation factors appropriate for inclusion in staff's net benefits analysis.

Capacity Factor: To determine an appropriate capacity factor for Trojan for 1993, TBA considered the following five factors: (1) PGE's capacity factor projections for Trojan; (2) the capacity factor achieved at similar plants; (3) the impact of the steam generator issue on Trojan's capacity factor; (4) the impact of PGE's outage planning deficiencies; and (5) the impact of Trojan's twelve-month operating cycle.

To make its determination, TBA utilized the median of 1991-1993 average design electrical rating net capacity factors for 50 large domestic reactors like Trojan, rated at 1020 MW and above. It then adjusted that figure to eliminate the impact of steam generator tube problems, then credited Trojan for the adverse impact of its twelve-month operating cycle. TBA's quantification determined that Trojan's capacity factor should have been at least 67.6 to 71.6 percent. Staff chose the midpoint of this range, 69.6 percent, as its imputed capacity factor for Trojan.

PGE contends that staff's projection is too high. It first challenges TBA's use of the median 1991-1993 average design electrical rating net capacity factors for domestic reactors rated at 1020 MW and above. It contends that the most appropriate comparison group for a capacity factor quantification consists of plants larger than 1000 MW and placed in service between 1971 and 1981. We disagree. Again, PGE's narrowly defined comparison group inappropriately skews the results of its analysis. Its comparison group consists of only twelve plants, many of which were out of service during extended periods of time, thus lowering the capacity factor average. It is also important to note that TBA's comparison group included many boiling water reactors (BWR), which had an average capacity factor that was 8.6 percent less than pressurized water reactors like Trojan in 1991-1993. The influence of BWR units in TBA's comparison group, combined with PGE's own projection for a significant capacity factor improvement after steam generator replacement, supports TBA's conclusion that Trojan's capacity factor should have been at least 67.6 to 71.6 percent.

PGE also challenges TBA's adjustment to the capacity factor to account for steam generator problems. TBA's adjustment was based on an Electric Power Research Institute (EPRI) report formulated specifically for the purpose of determining the impact of steam generator problems on capacity factor. We do not find PGE's argument persuasive and reject it.

Steam Generator: PGE's least-cost plan analysis includes steam generator repair costs in O&M expenditure projections, steam generator replacement costs in capital expenditure projections, and capacity factor reductions for steam generator repair and replacement activities through 1996. TBA concluded that PGE's liability for the steam generator problems was not accounted for in its LCP. This issue is further addressed below as part of Issue S-49, Steam Generator Plugging, Sleeving, and Analysis and Spare Reactor Coolant Pump Motor. We disallow both the inclusion of steam generator replacement costs from the LCP (approximately $183.1 million) and the post-1991 capital expenditures.

As an additional issue, PGE contends that staff's use of the LCP inappropriately assigns the benefit of a planned 45 MW uprate to the ratepayers. An uprate is an increase in a plant's electrical production capacity and usually comprises a change in plant operating parameters, such as pressure or temperature, that allow existing plant equipment to produce a greater amount of electricity. PGE's 1992 Plan includes a 45 MW increase in Trojan capacity at the time of planned steam generator replacement in 1996. PGE argues that the benefits of the added capacity should be removed if no steam generator replacement is included in the net benefits analysis. PGE explains in its rebuttal testimony:

> If we must assume that customers would not pay for the cost of the new steam generators, then we must also assume that they do not receive any incremental benefits associated with the new steam generators.

The replacement of the Trojan steam generators would have provided PGE with the opportunity to "piggyback" the costs associated with obtaining regulatory approval for a power uprating onto the costs necessary to obtain regulatory approval for operation with the replacement steam generators. TBA concluded, however, that PGE could have achieved the 45 MW uprate with the original steam generators, had they not been defective. In fact, PGE considered a 45 MW uprate using the original steam generators in the late 1980s. PGE ultimately determined that the uprating was not feasible, however, due to the defects in the original steam generators that required a significant number of tubes to be plugged. Moreover, without the many plugged tubes, an uprating could have been accomplished at a cost of only a few million dollars, as compared to the significant costs of steam generator replacement. For these reasons, we conclude that the benefits of the additional 45 MW of additional capacity that PGE included in its least-cost plan scenario are properly included in the net benefits analysis.

Staff's Conclusions from Net Benefits Analysis

Adjusting PGE's least-cost planning results, staff concluded that, for the 1995-2011 test period, the premature closure of Trojan resulted in a negative net benefit of approximately $23.6 million. In reaching that conclusion, staff used the midpoints of the ranges developed by TBA for 1993 fixed O&M, fixed O&M escalation factors, and capacity factors. Staff also removed the costs of steam generator replacement from the LCP results, for reasons addressed below as part of Issue S-49, Steam Generator Plugging, Sleeving, and Analysis and Spare Reactor Coolant Pump Motor.

Based on its net benefits analysis, staff concludes that continued operation of Trojan would have cost less than immediate shutdown in the absence of steam generator defects and management errors at Trojan. Accordingly, staff recommends that we should hold PGE's ratepayers harmless from the effects of the steam generator defects and management failures by disallowing $23.6 million of the company's remaining investment in the plant.

Position of Other Parties

As an additional issue, CUB and Kullberg argue that the decision to build Trojan was imprudent in and of itself. CUB compares Trojan's cost with the cost and performance of coal plants after Trojan was completed and brought on line. The comparison is not well supported. A prudence review takes into account the information that was available to decision makers at the time the decision was made. It does not engage in hindsight or second-guessing; to do so would be unfair. PGE could not have known those data about coal plants at the time it decided to build Trojan. The record does not contain evidence about what information was available to PGE when it decided to build Trojan, and it cannot support a decision of any kind on that issue.

Moreover, every rate case the Commission has decided since Trojan began operating has included Trojan in rate base. It would be inappropriate now to overturn the decisions in each of those rate orders from 1976 on.

Disposition - S-50: Remove Additional Fixed Costs--Net Benefits Analysis

We conclude that the allocation of the remaining Trojan investment is properly determined by a net benefits analysis. The purpose of a net benefits test is to identify the point at which ratepayers are indifferent between the options of continued operation of Trojan and shutdown and construction or acquisition of replacement resources. Application of the test is intended to hold ratepayers harmless for a utility's poor operation or management.

Staff evaluated numerous issues presented by a net benefits review. It retained an expert witness, TBA, to review PGE's operation and management of Trojan. In its review, TBA applied a reasonable person standard, similar to that commonly employed in utility prudence review proceedings. TBA based its evaluation on information available to a decision maker at the time of the decision. Based on TBA's findings, staff completed a quantitative analysis to determine whether assessing ratepayers 100 percent of Trojan's remaining costs is in the public interest. After revising its net benefits analysis to incorporate some changes suggested in PGE's rebuttal testimony, staff determined that the premature closure of Trojan resulted in a negative net benefit of approximately $23.6 million. With the adjustments described below, we adopt staff's net benefits analysis.

Adjustments to Staff's Net Benefits Case: Staff's initial net benefits analysis did not include seven potential adjustments that were not quantified or that were raised during the Phase II hearings. We have reviewed those adjustments and adopt them with the correction and exception noted below. We also adjust the estimated net benefit to recognize the interaction among the individual adjustments, as discussed below.

1. **45 MW Increase in Trojan Capacity.** Staff's analysis assumed that the 45 MW uprate would have taken place in 1996, along with the steam generator replacement, as PGE had assumed in its LCP. However, if the steam generator degradation had not occurred, the increase could have been achieved without replacing the steam generators. Assuming a date earlier than 1996 would reduce the net benefit of closing Trojan, because the extra 45 MW would obviate the need for 45 MW of power from other resources. Staff included the 45 MW capacity increase in its net benefits analysis starting in July 1996.

CUB calculated that moving the start date back to the beginning of the test period (January 1995) would reduce the net benefit of closing Trojan by $7.7 million (PGE share, 1995 dollars). We find that CUB's calculation is incorrect because: (1) it does not account for the variable O&M associated with additional generation; (2) it does not recognize that the costs used are expressed in 1993 dollars; and (3) it does not discount the value of the additional generation properly. The corrected figure (using CUB's assumed 65 percent capacity factor) is $6.1 million.

We find the corrected adjustment reasonable and adopt it.

2. **Capacity factor.** In its capacity factor quantification, TBA determined that the industry median capacity factor was depressed as a result of steam generator problems. Relying on a study by EPRI, TBA concluded that the capacity factor should be increased by 2.6 percent to adjust for the steam generator tube problems. At hearing, however, CUB demonstrated that TBA had overlooked the fact that the EPRI study also indicated that steam generator replacement activities reduced capacity factors by an additional .65 percent. TBA testified that its imputed capacity factor range should be increased by this amount to accurately account for all of the effects of the steam generator problems. Staff, in turn, testified that such an adjustment in TBA's range would also increase its mid-point imputed capacity factor by .65 percent, for a value of 70.25 percent. Increasing capacity factor by .65 percent reduces the net benefits of closure by $20.5 million (PGE share, 1995 dollars).

We find this adjustment reasonable and adopt it.

3. **Fixed O&M.** Staff's base case used the mid-point of TBA's O&M range, $102.25 million, for allowable fixed O&M for 1993. TBA's nonfuel O&M, however, is not the same as PGE's fixed O&M. PGE treated variable O&M as separate from nuclear fuel costs. Therefore, allowable fixed O&M should be determined by subtracting variable O&M from TBA's nonfuel O&M estimates.

At the 60 percent Trojan capacity factor assumed for 1993, variable O&M totals $5.8 million. Subtracting this figure from TBA's nonfuel O&M produces a range for fixed O&M of $93.7 million to $99.2 million, with a midpoint of $96.45 million. This $5.8 million reduction in fixed O&M, extrapolated out over the study period, and using the O&M escalation figure in staff's surrebuttal testimony, reduces the net benefit of closure by $51.8 million (PGE share, 1995 dollars).

We find this adjustment reasonable and adopt it.

4. Nuclear Fuel Costs. Nuclear fuel estimates are necessary to compare the cost of operating Trojan at a given capacity factor to the cost of replacement resources used to generate an equivalent amount of energy. In combining the results from the two parts of the LCP, staff assumed that the 1992 Plan numbers for fuel costs in Case 1b were calculated in the same manner and contained the same assumptions as the Update's Scenario 3. Based on that assumption, staff combined the results of Case 1b and Scenario 3 for use in its net benefits analysis. PGE explained, however, that it used lower nuclear fuel costs during phase-out in the Update than in the 1992 Plan. Accordingly, the net benefits analysis should use consistent assumptions to estimate nuclear fuel costs. This correction increases the net benefit of closure by $25.7 million (PGE share, 1995 dollars).

We find this adjustment reasonable and adopt the updated figure.

5. Transition Costs. Staff reduced the cost of the immediate shutdown alternative to recognize the fact that PGE has experienced lower transition costs than assumed in the least cost plan. Staff's net benefit estimates do not include any corresponding transition cost savings under continued Trojan operation with shutdown in 2011. If transition costs in PGE's LCP were overestimated for immediate closure, staff believes that they may also have been overstated for continued plant operation. Staff concluded that some savings in transition costs after 2011 would be likely. Recognizing these savings would reduce the net benefit of immediate closure. Staff does not suggest a figure to represent savings in transition costs after 2011, although CUB quantifies the savings at $30.8 million, starting from the same $65.6 million for which staff adjusted the cost of immediate closure (PGE share, 1995 dollars).

PGE describes its reduction in transition costs over its LCP projections as the result of aggressive and quick cutting of costs. Staff does not challenge that description.

We do not adopt this post-2011 adjustment. Staff was not certain that transition costs were actually overstated for continued plant operation, and did not quantify the amount. CUB's quantification, in view of staff's circumspect approach to this issue, is not supported by the record. CUB simply assumes that the savings would be the same for continued operation. Moreover, PGE achieved some of the savings by aggressive action. Imputing a lower than projected cost to transition in 2011 is tantamount to penalizing PGE for acting quickly to cut costs.

6. Carrying charges. It is standard industry practice to recognize a small amount of capital replacement in the fixed O&M assumptions for combustion turbines. While PGE's fixed O&M assumptions were consistent with this practice, the company also accounted for capital replacement costs in carrying charges in the 1992 Plan. To conform with other forecasts in the industry, and to eliminate any double-counting of costs, PGE subsequently reduced the carrying charges to eliminate the allowance of capital replacements beginning with its 1993 avoided cost filing.

PGE argues that the net benefit analysis should also use the carrying cost rate from the 1992 Plan corrected to eliminate the inclusion of interim capital additions for new combustion turbine generating plants. We agree. Although the reduction in capital costs exceeds PGE's fixed O&M assumptions, the adjustment to the carrying charges reflects industry practice of assuming very small capital additions for combustion turbines. Moreover, we approved PGE's projections of the capital costs of combustion turbines in acting on the company's 1993 and 1994 avoided cost filings. The net benefits test should use the capital additions assumptions as updated in those avoided cost filings. Using corrected carrying cost rates increases the net benefit of closure by $68.9 million (PGE share, 1995 dollars).

We find this adjustment reasonable and adopt it.

7. Capital Costs of New Gas-Fired Resource. Staff's net benefit figures for the cost of replacement resources are based on PGE's least-cost planning estimate of the capital cost of a combined-cycle combustion turbine, the principal resource replacing Trojan. PGE's figure is lower than those being used by PacifiCorp and the NWPPC in their current planning processes. PGE estimates the capital costs for the turbine at $550/KW, PacifiCorp at $586/KW, and NWPPC at $630/KW. PGE has not shown why its estimate is so much lower than that of the other entities. Substituting PacifiCorp's estimate for PGE's would make the net benefits analysis more negative by $16.0 million (PGE share, 1995 dollars).

We conclude that PGE has not shown why its estimate is more reasonable than the other, higher estimates in question. We find it more reasonable to adopt the middle estimate, $586/KW, and adjust staff's analysis accordingly.

Adjustment for Interactions. A further change in the net benefits estimate is needed to account for interactions among the individual adjustments described above. Increasing capacity factor by .65 percent, for example, increases the value of advancing the 45 MW capacity increase at Trojan to January 1995. Revising carrying charges changes the effect of updating the capital cost of replacement resources. Using the staff's net benefits model, we find that recognizing all the interactions increases net benefits by $3.0 million, and we adjust the net benefits estimate accordingly.

Summary of Adjustments

The following table summarizes the effects of the adjustments discussed above:

Staff's net benefits analysis result	-$23.6 million
Adjustments to Staff's Calculations	
January 1995-June 1996 uprate to 45 MW	-$ 6.1 million
Increase capacity factor by .65 percent	-$20.5 million
Decreasing Imputed Fixed O&M by $5.8 million	-$51.8 million
Update to nuclear fuel assumptions	+$25.7 million
Update to staff's carrying costs	+$68.9 million
Update to capital costs of replacement resources	-$16.0 million
Adjustment for interaction	+$ 3.0 million
Total effect of adjustments	+$3.2 million
Total of adjustments and staff's net benefits calculation	-$20.4 million
Post-1991 disallowances	-$17.1 million
Total disallowance including post-1991 expenditures	-$37.5 million

Remaining Trojan Investment	Ratepayer Share	
$288.2 million	$250.7 million	87 percent

We find that with these adjustments, the net benefits analysis approximates the point at which ratepayers are indifferent between continued operation of Trojan and shutdown, with replacement of the generating resource. We also find that this recovery under the adjusted net benefits analysis is in the public interest. ORS 757.140(2).

Transition Costs

TBA also reviewed PGE's 1993-1996 transition costs. PGE defined transition costs as "the operations and corporate overhead costs associated with closing Trojan, operating and maintaining the spent fuel pool, and securing the plant until dismantlement can begin." TBA determined that the transition costs included in the proposed test years are reasonable, and staff recommends full recovery of the amount requested by PGE. We adopt staff's recommendation.

S-45: Trojan Overtime

Staff proposes the removal of all overtime compensation budgeted by PGE for the Trojan plant in its filing. Staff notes that the plant was permanently shut down in January 1993, and requires only security, monitoring, and maintenance staff. Staff believes that PGE's personnel levels are adequate to accomplish those activities without the need for overtime. PGE disputes staff's proposed adjustment, but does not provide sufficient explanation to justify recovery of those costs. After a review of this matter, we agree that the budgeted overtime should be removed.

S-46: Trojan Investment Classification

The Commission has adopted the FERC Uniform System of Accounts as a basis for utility accounting requirements. The Uniform System of Accounts is a comprehensive basis of accounting and provides, among other things, distinct accounts for assets and other debits.

In its filing, PGE proposes to leave certain Trojan assets in FERC Account 101, Plant in Service, an account designated for original costs of electric plant owned and used by the utility in its electric utility operations. PGE believes that the assets, which primarily include the spent fuel pool and related systems, as well as the administrative buildings, should continue to be classified as plant in service because they remain used and useful for the purpose for which they were intended. Staff disagrees with PGE's proposal and recommends that all net investment in Trojan systems, including Trojan Material and Supplies Inventory, be placed in FERC Account 182.2, Unrecovered Plant and Regulatory Study Costs. That account is defined to include significant unrecovered costs of plant facilities that have been prematurely retired. Because both accounts are included in PGE's rate base, transferring investment between the accounts will not affect the rate base.

PGE and staff agree that the placement of plant in FERC Account 101 means that the plant is "used and useful in the public service." PGE contends that that requirement is met, because the Trojan plant remaining in that account protects public health and safety, provides security, or provides office space and facilities for the employees that remain on the site. As staff notes, however, the original purpose of the assets in question was to be part of an operating plant that was providing service to rate payers. That plant has now been permanently shut down, and those assets are now used only to provide the service necessary for safety and asset preservation pending decommissioning and dismantling of the plant. Moreover, while the spent fuel at Trojan is the result of "used and useful" service by the plant, it is being stored at Trojan only because the United States Department of Energy (USDOE) has failed to establish a permanent federal repository for nuclear waste. In short, the continuing activities at Trojan are related to decommissioning, not productive operation of the facility.

We acknowledge that there is no prescribed method of accounting for nuclear plants that are in the process of being decommissioned. FERC is currently working on a position paper regarding this issue, but it has not yet been issued. The Financial Accounting Standards Board (FASB), however, has taken a position on accounting for plant that is removed from service. In its Statement 90, the FASB states:

> When it becomes probable that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-progress or plant-in-service.

For these reasons, we find that the Trojan plant is no longer used and useful. All the Trojan plant investment, including accumulated depreciation, accumulated deferred income tax, and deferred investment tax credit, as well as Trojan Materials and Supplies Inventory, should be transferred to FERC Account 182.2, Unrecovered Plant and Regulatory Study Costs. PGE's filing should be modified accordingly.

S-47: Trojan Salvage Proceeds

Staff also recommends that the unrecovered Trojan plant placed in FERC Account 182.2 be reduced to reflect a greater amount of projected recovery through salvage sales of surplus Trojan assets. Staff believes that PGE's original estimate of salvage recovery of $6.7 million is reasonable for the equipment that was included in the estimate, but adds that the estimate does not include any recovery for the buildings or certain installed plant equipment. Because the costs of the installed plant equipment and unused buildings are significant, staff proposes that the estimated salvage proceeds be increased by $6 million, for a total amount of $12.7 million, PGE share.

PGE acknowledges that the revised estimate of salvage recovery does not include any recovery for buildings and only $506,000 for installed plant equipment. The company argues, however, that it is unrealistic to expect that salvage sales will exceed the level predicted. PGE notes that it has aggressively attempted to market installed plant equipment to foreign nations, but adds that no major sales are pending. It also cites numerous efforts to market the approximate 149,000 square feet of space available for sale or lease at Trojan. Those efforts, however, have generated little interest.

Both PGE and staff agree that the sales of surplus Trojan assets through 1995 and 1996 are difficult to determine. The book value of the underlying Trojan assets, however, is significant. According to PGE's numbers and classification, the value of plant items and materials and supplies is approximately $232 million after reductions of PGE's estimated salvage sales. We share staff's concern that the use of low salvage estimates for those assets would cause the rate base and amortization expense to be too high.

Accordingly, we find staff's proposed adjustments reasonable and adopt them. If actual salvage is less than staff's projection, PGE's loss will be limited to the return on the difference between staff's estimate and the company's estimate for the period between the end of this rate case and the end of the next one. Actual recovery will have been determined by the time of that next rate case, and any shortfall can be returned to PGE's rate base.

S-48: Trojan Decommissioning

Definition of Decommissioning. According to the Rules and Regulations of the NRC (10 CFR 50.2), "'Decommission' means to remove [a facility] safely from service and reduce residual radioactivity to a level that permits release of the property for unrestricted use." In this docket, staff has used a more inclusive definition of decommissioning. The NRC's definition refers only to those portions of a facility affected by radioactivity, but staff uses the term to include all activities related to removing total plant from service and restoring the site to unrestricted use. We adopt staff's usage of "decommission." We also adopt staff's definition of decommissioning cost as the total cost of removing Trojan from service, net of any salvage recovery.

Decommissioning Costs: Capital or Noncapital? When we entered our decision in DR 10, staff considered decommissioning costs to be a noncapital expense. *See* Order No. 93-1117 at 14. In the meantime, staff has reconsidered its position. It now considers decommissioning costs to be capital costs. Capital costs may be recovered under ORS 757.140(2).

Staff reached its current conclusion about decommissioning costs by determining that decommissioning costs are conceptually equivalent to the negative net salvage value of property removed from service.[20] If that equivalence is valid, decommissioning costs are capital costs because salvage value is associated with capital investment (property).

Net salvage value (the difference between salvage value and cost of removal) is a depreciation concept. Depreciation is the method this Commission uses to provide for the recovery of the total investment in property and the cost of removal of that property from service at the end of its estimated life.[21] Positive net salvage value reduces the rate of depreciation. Negative net salvage value increases the depreciation rate. If the cost of removal is greater than the salvage value of the property, then the sum to be recovered will be greater than the original investment.

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[20] Staff's determination is supported by Frank K. Wolf and W. Chester Fitch, *Depreciation Systems* (Ames, IA: Iowa State U/ Press, 1994), who refer to decommissioning as "large negative salvage" (p. 7) and as "significant negative net salvage"(p. 52).

[21] ORS 757.140(1) requires each public utility to carry an adequate depreciation account. Under that provision, the Commission ascertains and determines the proper rates of depreciation.

The following formula expresses the equivalence of decommissioning costs and net negative salvage:

$$D = SV - CR$$

where D = decommissioning costs; SV = salvage value; and CR = cost of removal. We agree with staff that decommissioning costs are equivalent to negative net salvage value and are therefore capital costs.

Background of Trojan Decommissioning. When Trojan went into service in 1976, PGE included an allowance for net salvage in its depreciation rates. Negative net salvage percentages were attributed to the Structure & Improvements account and the Reactor Plant Equipment account. By Order No. 79-055, the Commission required the company to make a decommissioning cost study as the basis for estimating the cost of taking the plant out of service. PGE submitted the study and a funding proposal in 1979. The Commission approved the plan and the funding proposal in Order No. 80-612, issued August 18, 1980.

PGE's 1979 plan called for the plant to lie dormant for 100 years after its closing, at which time it was to be dismantled. PGE proposed to fund the decommissioning through an internal sinking fund account within its depreciation reserve.[22]

In Order No. 91-186 (UE 79), consistent with rule changes of the NRC, the Commission adopted a new decommissioning plan and cost estimate. The new plan called for the immediate dismantling of the plant at the end of its estimated life (2011). The decommissioning fund was changed from an internal fund to an external trust fund administered by an independent trustee, pursuant to NRC requirements. The fund balance was $48.9 million at the end of 1993.

Current Plan. In this docket, PGE has proposed a revised decommissioning plan. The principal elements of its plan are:

1. Early large component removal. The company plans to remove the steam generators and pressurizer for burial by December 1995.

2. Construction of a "dry" on-site fuel storage facility for long-term storage of spent nuclear fuel. The facility would be completed by 1998 and the spent fuel

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[22] A sinking fund is designed to produce a desired sum of money at the end of a given time period. A payor makes a series of payments into an interest-bearing account throughout the period. The sum of the payments plus accrued interest will equal the desired total at the end of the period. "Internal" in this discussion means internal to PGE. PGE established the sinking fund as part of its depreciation reserve. Interest accrued at the company's rate of return. The company was to maintain the fund.

would be stored there until shipment to a permanent federal storage facility (target date: 2018).

3. Removal and dismantling of all contaminated systems and some building demolition from 1998 through 2002.

4. Site restoration activities. After the shipment off-site of the spent fuel in 2018, all facilities with no further value will be dismantled and the site made available for unrestricted use. This will occur from 2018 through 2023.

PGE notes that early implementation of decommissioning will give its customers the benefit of current low burial rates and mitigate the risk of losing access to a low-level radioactive waste burial site.

Funding of the Current Decommissioning Plan. Beginning in 1995, PGE proposes to contribute $14,041,000 annually to the external trust fund. The contribution will continue through the year 2011. The period ending in 2011 was chosen for distributing decommissioning costs because that is the period over which the Trojan closure is expected to produce benefits. After 2011, Trojan would have been replaced by other resources in any case, so the generation of ratepayers after 2011 should not share in decommissioning costs.

PGE's proposal to contribute an equal amount each year to the external trust fund is a departure from the method of contribution adopted in UE 79. In that docket, it was assumed that Trojan would operate until 2011, and the Commission adopted a funding plan under which each generation of customers would contribute equally on a real levelized basis, with payments increasing over time to offset the effect of inflation. The real levelized funding plan would have matched costs with benefits received by the ratepayers. That is, ratepayers receiving the benefit of the plant would pay for its decommissioning. PGE's current contribution under this plan is $11,220,000 in 1994, which would have increased to $21,120,000 by 2011.

Trojan was shut down in 1993, however. The company now proposes a nominal level contribution. The payment into the decommissioning fund will be the same each year. Under this plan, in real terms, decommissioning costs to future ratepayers will decline because of inflation. The increased level of current contribution is required because Trojan shut down earlier than expected. The current payment to the decommissioning fund is inadequate and must be increased.

Even with the proposed increase in annual contribution, the company will have to borrow to bridge its needs. As currently estimated, however, the cash flows will eventually fund the cost of decommissioning including repayment of the interim financing. The company's investment strategy concentrates on municipal and corporate bonds.

PGE's Efforts to Involve Other Entities. In DR 10, we imposed the condition that PGE involve other entities in its decommissioning efforts. PGE has held discussions with the NRC, USDOE, EPRI, and other utilities. It has performed work relating to steam generators for Duke Power's Catawba plant, and has other proposed programs. The NRC has shown interest in performing containment tendon grease leakage studies and electrical cable aging studies at the Trojan facility.

Staff's Review of PGE's Plan and Funding Proposal. As part of its case, staff reviewed both PGE's decommissioning plan itself and the proposal for funding it. Staff asserts that PGE's decommissioning plan meets all criteria of the NRC and the Oregon Energy Facility Siting Council and recommends that we adopt it. In addition, staff states that PGE's proposal is the least-cost decommissioning option.[23] Staff also notes that, as the process of decommissioning evolves, PGE will doubtless find it necessary to make changes in its total cost estimate. The plan and its funding mechanism should therefore be subject to regular, ongoing review by the Commission and staff. Necessary changes in authority granted to PGE by the Commission can be made in future dockets.

Positions of URP and Kullberg. URP first contends that PGE's proposal is not prudent under the circumstances and that ratepayers should not have to pay for it. URP believes that PGE's decommissioning plan disadvantages PGE in its pending suit against Westinghouse because the large component removal destroys evidence that PGE needs in its lawsuit and possibly in other forums.

Second, URP contends that the NRC may order modifications to PGE's decommissioning plan and that Commission approval is therefore premature. Kullberg also argues that decommissioning costs should not be reflected in rates prior to NRC approval of the plan. Kullberg has specific disagreements with PGE's plan as well, and urges that decommissioning should be delayed to gather more information and reduce uncertainty about a number of elements of the plan.

In response to URP's first contention, we are not persuaded that PGE's removal of the steam generators will harm ratepayers, especially since this order disallows the post-1991 steam generator costs. The first of URP's arguments is rejected.

As to waiting for NRC approval, we understand that the final plan may differ in some respects from the current proposal. We also understand that as decommissioning proceeds, it may be necessary to make still further revisions in the plan or its financing. We acknowledge that there is a great deal of uncertainty in the whole area of decommissioning. Therefore, PGE's decommissioning plan and its funding mechanism will be subject to regular, ongoing review by the Commission and staff. Necessary changes in authority granted to PGE by the Commission can be made in future dockets.

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[23] As part of the planning process, PGE's consultant evaluated four decommissioning options available to PGE and estimated their cost in 1993 dollars. PGE's option is the least costly of these four options.

We conclude that it is not necessary to wait for NRC approval before approving PGE's decommissioning proposal.

As to the request that decommissioning be delayed pending further study, we find it more likely than not, based on the record before us, that delay in implementing the plan will increase the costs of decommissioning. That is an undesirable outcome. Moreover, early decommissioning allows PGE to take advantage of disposal site availability. Continued Commission oversight of the decommissioning process will address the question of changing circumstances as decommissioning proceeds. The arguments for delay are rejected.

DR 10 and Recovery of Decommissioning Costs. In DR 10, Order No. 93-1117, we concluded that we would consider favorably allowing PGE to recover Trojan's decommissioning costs in rates, if PGE met the following conditions:

1. PGE must prove all six assumed facts in a rate case or similar forum. (See the section above, "Applicable Law," for the six assumed facts.)

2. PGE must show that it pursued the least-cost decommissioning option consistent with directives from the Nuclear Regulatory Commission and other agencies.

3. PGE must show that it has made a reasonable effort to ascertain if other entities wishing to gain valuable experience in decommissioning a nuclear plant of this size would participate in and support its decommissioning activities.

4. PGE must report within 30 days any settlement or award related to decommissioning costs for the Trojan plant.

5. PGE must provide satisfactory evidence with regard to any other matter the Commission deems pertinent to a decision in a rate proceeding.

Disposition of the DR 10 Conditions. We conclude that PGE has met the DR 10 conditions. The first condition, proof of the six assumed facts, was discussed above, in the section titled "The DR 10 Requirements," p. 27. We found that PGE has shown all but one of the six facts. We have discretion to allow recovery of decommissioning costs, however, in view of PGE's substantial compliance with the requirement that it prove the assumed facts.

As to the second condition, based on current information, PGE's chosen plan is the least-cost option. Third, PGE has made good faith efforts to involve other entities in its decommissioning efforts; we note its efforts to contact the NRC, EPRI, the USDOE, and other utilities. The fourth condition, report of any settlement or award related to decommissioning costs, is not yet ripe. We continue to impose this requirement on PGE. We have not imposed the fifth condition.

We approve PGE's decommissioning plan and funding plan for inclusion in rate base on the effective date of the tariffs adopted in this order.

S-49: Steam Generator Plugging, Sleeving, and Analysis and Spare Nuclear Reactor Coolant Pump Motor

Steam Generator Issues:

The steam generators figure in the analysis of Trojan-related costs in two ways. First, the cost of *replacing* the degraded steam generators was imputed in PGE's 1992 Least-Cost Plan and 1993 Update. Second, PGE incurred capital expenses relating to *repairing* the steam generators in the time between its last general rate case, UE 79, and this rate case. TBA's evaluation of the steam generator issue addresses both of these costs.

Replacing the generators: In its least-cost planning process, PGE considered replacing the steam generators. PGE included the cost of replacement in its least-cost analysis of closing Trojan. The expected cost of replacing the generators in 1996 is $183.1 million. Staff recommends removing from the net benefits analysis all costs associated with replacing the steam generators. If the cost of replacing the steam generators were included in the net benefits analysis, the cost of continued operation would be higher and the net benefit of closure would therefore be greater. Staff's proposal imputes to PGE the cost of replacing the steam generators, for purposes of the net benefits analysis.

Repairing the generators: After January 1, 1992, PGE incurred capital costs for plugging and sleeving the generators and analyzing the problem. Post-1991 Trojan-related capital expenditures have never been in PGE's rate base. PGE proposed to have them become rate base items for UE 88 recovery purposes. Staff recommends disallowance of the steam generator capital expenditures. The total amount of recommended disallowance is approximately $14.9 million.

In considering how to treat the cost recovery associated with the steam generators, TBA reviewed Westinghouse engineering and design activities and PGE's purchase, operation, maintenance, and care of the Trojan steam generators. The review covers the period from 1968, when PGE purchased the generators from Westinghouse, through 1993, when PGE decided to close Trojan.

PGE noted significant degradation of the steam generators in 1989. By 1991, over 25 percent of the steam generator tubes were either plugged or sleeved.[24] The

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[24] Sleeving is a process whereby another tube is permanently inserted into a degraded tube.

generators had degraded to the point that PGE had planned to replace them in 1996. TBA concluded that Westinghouse design flaws were the root cause of the steam generator degradation. TBA found no imprudence on PGE's part with respect to its maintenance and operation of the generators.

Staff argues that we have the discretion to hold PGE responsible for the costs associated with the steam generator problems and recommends that we exercise our discretion in favor of the ratepayers. Staff's position derives from TBA's recommendation that PGE be held liable for steam generator costs even absent a finding of negligence on PGE's part.

Staff notes that the Commission has broad discretion when it comes to ratemaking. As the Oregon Supreme Court said, "The [Commission] appears, therefore, to have been granted the broadest authority -- commensurate with that of the legislature itself -- for the exercise of [its] regulatory function." *Pacific N.W. Bell v. Sabin*, 21 Or App 200, 214 (1975). Staff concludes that we have the discretion to disallow the costs associated with steam generators and to remove the cost of replacing them from the net benefits analysis.

Staff supports its conclusion by referring to *Pennsylvania Public Utility Commission v. Philadelphia Electric Company*, 561 A2d 1224 (1989). In that case, the Pennsylvania Supreme Court dealt with an order of the Pennsylvania Public Utility Commission in which that commission disallowed replacement power costs stemming from two shutdowns of a nuclear power plant. The second shutdown occurred because of a manufacturing defect, which the court said could not be attributed to the utility. The court nevertheless held that the commission was correct in assigning replacement power costs to the utility rather than to ratepayers. The court reasoned:

> By disallowing the replacement costs, the Commission held that the utility and not the ratepayers were in a far superior position to seek redress for the defects and negotiate contractual protections to minimize any future problems. [W]e believe a utility company is in a better position to prevent an occurrence or provide for protection against any such occurrence. After all, it was the utility which chose the contractor, negotiated the contract, and is in a position to seek damages for any losses sustained under the contract. While the utility may have to bear the initial losses incurred as the result of its contractor's negligence, it is in a far better position to aggressively pursue the tort-feasor for reimbursement. If we were to hold otherwise, the utility would have no incentive to pursue the tort-feasor, having already received full compensation for its losses. 561 A2d at 1228.

Staff also supports its position with reference to product liability law, which illustrates that the law can impose a burden on a party not judged to be at fault. If a customer is injured by a product through no fault of her own, for instance, product liability law imposes liability on the merchant, even if faultless, because the merchant is better situated than the customer to pursue remedies against the manufacturer. Restatement (Second) of Torts, Section 402A.

PGE argues that there is no legal precedent for holding it strictly liable for the defective steam generators; that TBA took a contrary position in another case; that staff's various legal analogies (see below) are inapposite because this is not a tort case but a ratemaking proceeding; and that to hold it strictly liable would be to set a dangerous new precedent. PGE also makes the policy argument that if we impose steam generator costs on PGE without a showing of imprudence, it will eliminate a protection now available to utilities when they seek cost recovery for expenditures.

Disposition:

We are persuaded by staff's arguments. Even if PGE is faultless, PGE is better situated to pursue remedies against Westinghouse than its ratepayers are. PGE is correct when it argues that this is a rate case, not a tort case, and that the legal precedent staff cites can be distinguished factually from the present case. However, someone must bear the costs relating to the steam generator defects. As between PGE and the ratepayers, we find it fairer to assign the costs to PGE, based on the reasoning in *Pennsylvania Public Utility Commission v. Philadelphia Electric Company.* That case is different on its facts because the vendor and the utility were in an ongoing contractual relationship, but the principle enunciated applies to the present case, as does the principle of product liability law stated above.

The fact that TBA took a contrary position in another case does not decide the issue now before us.

Finally, PGE argues that imposing steam generator costs on it in the absence of imprudence means that utilities lose the protection of prudence as the basis for cost recovery when they purchase goods or services from another. The Commission decides cost recovery issues on a case by case basis. No future outcome is determined by the decision to impute the cost of steam generator replacement to PGE by removing their cost from the net benefits analysis and disallowing the post-1991 plugging, sleeving, and analysis costs.

Spare Reactor Coolant Pump Motor:

This is another post-1991 Trojan-related expense that staff recommends should be disallowed. Trojan had four coolant pump motors that circulated water to cool the reactor. These pumps were required for the safe operation of Trojan, and if one motor had failed, Trojan would have had to be taken off line. It could have taken up to nine months to repair or replace a motor.

In 1986, PGE assessed the need for a spare motor. PGE inspected the existing motors, which had operated since 1976, and found them to be in excellent condition. PGE decided against purchasing a spare motor. In 1988 and 1989, PGE again studied the issue of purchasing a spare motor and explored several options, none of which involved PGE's sole purchase of a spare motor. PGE explored sharing a spare motor with another plant, for instance, and purchasing a motor stator (a motor component subject to the highest proportion of motor problems). PGE again decided against purchase. In Spring of 1991, it decided to purchase a spare motor from Westinghouse for $2.2 million. When PGE decided to close the plant in 1993, the motor had not yet been delivered. PGE decided not to accept delivery, because to do so would significantly reduce the motor's salvage value.

PGE argues that its decision to purchase the motor was prudent, pointing out that between 1984 and 1988, 19 reactor coolant pump motors failed in the industry. Moreover, PGE is aware of at least 20 other nuclear power plants that purchased or had access to a spare reactor coolant pump motor. PGE argues that the costs of the motor should therefore be included in rates.

Staff opposes including the cost of the spare reactor coolant pump motor in rates. Staff argues that the 1991 decision to purchase the motor is not supported by an adequate analysis. Although PGE assessed its need for a spare motor in 1986 and 1988, it did not do a new assessment in 1991. There is therefore no record to show why PGE decided to purchase the spare motor by itself, or why it purchased an entire motor rather than a stator. Staff maintains that PGE's general discussion of the impact of an outage and its relatively old data on motor failures do not support such a large capital investment.

Disposition:

We conclude that the $2.2 million investment in the spare reactor coolant pump motor was not prudent and that the investment will not be allowed in rates. The 1988 studies explored options that are different from the one PGE chose in 1991, so PGE cannot use those studies to support its 1991 decision. The data from 1986 are too remote to rely on. Here, as with all issues in a rate case, PGE has the burden of proof, and has not carried it.

S-51: Remove Trojan Power Cost Deferral
S-52: Trojan Plant Income Tax Write-off Revision

PGE's initial filing included an estimate of the accumulated deferred income taxes associated with Trojan, including the write-off for tax purposes of the portion of Trojan that PGE considered to be no longer in service. Accumulated deferred taxes reduce rate base and give customers the time value of the income tax reductions. Total Trojan accumulated deferred income tax includes amounts related to several timing differences other than the Trojan write-off, including depreciation, decommissioning, retention plan, and other costs.

Staff originally accepted the amounts that PGE included in its filing for deferred taxes and write-off. In its rebuttal testimony, however, PGE revised the amount of accumulated deferred taxes for two reasons: to remove deferred taxes associated with Trojan excess power cost deferrals (Issue S-51) and to reflect a substantially reduced actual Trojan income tax write-off (Issue S-52).

On Issue S-51, PGE proposes to remove from rate base included in PGE's November 1993 filing the accumulated deferred income taxes for Trojan excess replacement power costs. The November filing incorrectly included $24.4 million of deferred taxes related to PGE's UE 85 and UM 594 power cost deferrals in the 1995 and 1996 rate bases. We will address those deferrals in separate dockets. That removal increases revenue requirement by $3,305,000 in 1995 and $3,337,000 in 1996. Staff agrees with PGE that these excess accumulated deferred taxes should be removed from rate base, and agrees as to the amount of taxes to be removed. We conclude that the Trojan excess power cost deferrals should be removed from rate base.

Issue S-52 deals with PGE's November 1993 filing, which forecast a Trojan tax write-off of $120.5 million. The actual write-off was only $66.6 million, which, PGE argues, increases the 1995 and 1996 rate base by $21.4 million and $22.3 million, respectively. According to PGE's revised calculation, the January 1, 1995, rate base reduction for accumulated tax deferrals related to a write-off would be $26.2 million, a $21.0 million change from the $47.2 million in PGE's initial filing.

Staff agrees that write-off tax deferrals should be revised, but differs with PGE on the proper amount. Staff challenges two elements of PGE's revisions. First, PGE's figures do not incorporate the effects of a tax write-off associated with the property it continues to classify as utility plant in service. In the discussion of Issue S-46 (Trojan Plant Classification) above, we concluded that Trojan assets are no longer used and useful for providing service, and are thus no longer to be classified as plant in service. According to staff, PGE's recommended rate base increases should be reduced by an initial amount of about $13 million, with appropriate changes for each of the test years.

Second, staff argues that we should use a different reserve for salvage than PGE does when it calculates the effects of a full tax write-off. PGE uses $19.3 million, or 20 percent of original cost, to lower the estimated total write-off. In its investment projections, PGE estimated salvage sales at $3.9 million. We have determined that the value of salvage sales should be set at $12.7 million (see discussion of Trojan salvage sales, Issue S-47 above). Staff proposes to use the same figure, $12.7 million, for both the reserve for salvage and the value of salvage sales. Staff's proposed figure is lower than PGE's, produces a higher initial deferred tax reserve, and lowers rate base by $2.6 million.

To summarize the effects of these two proposed changes, PGE supports a beginning amount of write-off of accumulated deferred taxes of $26.2 million. Staff proposes a beginning write-off of $41.7 million. $13 million of the difference derives from whether a full write-off is taken and $2.6 million is associated with the amount of salvage reserve to be included in estimates.

We previously found that Trojan should no longer be considered plant in service (Issue S-46). Accordingly, we adopt staff's position that the revision should incorporate the effects of a full write-off. We also determined that $12.7 million is the appropriate figure to use for Trojan salvage sales (Issue S-47). Therefore, we also adopt staff's position that $12.7 million is appropriate to use for salvage reserve. These adjustments increase revenue requirement by $871,000 for 1995 and $1,119,000 for 1996.

S-53: Trojan Intangible Asset Reclassification

PGE's November 1993 filing included Trojan Intangible Assets in total rate base but did not specifically identify them as Trojan rate base and did not include them in the "Trojan Only" analysis. Reclassifying them now will make them part of any Trojan Only analysis and result in a proper matching of Trojan rate base to the Trojan intangible depreciation expense. This adjustment increases 1995 and 1996 Trojan revenue requirement by $303,000 and $156,000, but is offset by a matching reduction to non-Trojan revenue requirement. Staff supports this reclassification. We find that Trojan intangible assets should be reclassified as PGE proposes.

Trojan Balancing Account

In the February 27, 1995, stipulation, PGE and staff agree that it is appropriate to vary the amortization of the Trojan investment to take into account the actual revenue collected from customers as a result of our decision in this case. Rather than creating a balancing account, the parties agree that incremental or decremental amortization expense amounts generated as a result of the stipulation will be accumulated in a Trojan Investment Recovery Account (TIRA). The TIRA is designed to provide a procedure to precisely accumulate actual revenue received by PGE as recovery of the Trojan investment based on amounts authorized in this order.

No party opposes the balancing account. We have reviewed this stipulation, attached as Appendix D, and find it reasonable. We adopt the stipulation in its entirety.

Other Adjustments

Staff and PGE agree on the following adjustments as well:

(1) To correct the nuclear fuel construction work in progress;

(2) To remove from all staff-proposed Trojan-specific revenue requirement recommendations and alternatives, all amortization expense, deferred income tax expense, and deferred investment related to the United States Department of Energy Decommissioning and Decontamination payment.

(3) To incorporate in the calculation of Trojan deferred income taxes the proper Schedule M adjustments, including the Trojan materials inadvertently left out of staff's Phase II Trojan deferred investment.

After reviewing these matters, we find these adjustments reasonable and approve them.

Appendix F attached shows the stipulated and unstipulated adjustments to PGE's original filing, along with their revenue requirement effect for 1995 and 1996. Appendix G shows the rate consequences of our decision, broken down by rate class, without and with the BPA residential exchange credit. Appendix H, attached, shows the percent of marginal costs attributable to each customer class.

CONCLUSIONS

1. Portland General Electric Company is a public utility subject to the Commission's jurisdiction.

2. The Commission should adopt the stipulations attached as Appendices B, C, D, and E.

3. Based on the record in this case, Portland General Electric Company's rates that result from the stipulations and the Commission's conclusions in the body of the Order are just and reasonable.

ORDER

IT IS ORDERED that:

1. The stipulations attached as Appendices B, C, D, and E are adopted in their entirety.

2. The other adjustments the Commission has made in the body of this Order are adopted.

3. PGE may file revised tariffs consistent with the stipulations and the findings of fact and conclusions in this Order to be effective April 1, 1995. PGE shall file such tariffs by March 30, 1995, or as soon thereafter as possible.

Made, entered, and effective MAR 29 1995.

Ron Eachus
Commissioner

Roger Hamilton
Commissioner

Chairman Smith concurs in part and dissents on the following issue:

S-38: Decoupling

I dissent from the Commission's conclusions and direction to PGE to proceed with decoupling, for the same reasons I dissented in Order No. 92-1673 (UM 409).

Decoupling was designed to promote energy efficiency and demand-side management (DSM). It is meant to remove disincentives to a utility's acquisition of demand-side resources from the traditional rate of return regulation framework. Order No. 92-1673 asserts that "[n]o other change in the regulatory system can ensure that we will move toward the goals of [reducing energy consumption]."

That assertion is even less supportable today than it was at the conclusion of UM 409. The marketplace has changed and will continue to change dramatically, requiring traditional regulation to evolve toward a more market-based approach. In the face of competition in generation and the prospect of comparability in the transmission system, electric utilities are responding by looking for ways to be and become lowest-cost providers.

This need (or perceived need) to be competitive drives inefficiencies out of the utilities' systems and produces a new, lower set of price signals. By definition, neither the customer nor PGE is likely to make uneconomic energy decisions. In the short term, the effect on DSM programs will be more than "perverse"; it could be close to fatal. That is, regulators may not have the leverage to require energy efficiency or DSM programs, because it will be even more difficult for programs to meet cost-effectiveness standards while remaining price competitive.

Not only will market prices be the controlling factor in customer response choices, but the inherent inability of traditional regulation to promote DSM will surface as well. Managing the proposed decoupling mechanism may well prove even more difficult, costly, and problematic than administering past and current DSM programs. For example, the administrative costs may be high, because the tariff will require "information on monthly revenues, incremental costs, and margin" as well as six-month reviews. I note that with regard to *incentive* mechanisms, the SAVE tariff (Schedule 101), which was considered a particularly effective DSM incentive mechanism, bogged down early in administrative burdens and disputes over measurements. Now the Commission has no way to require its continuation, and PGE has determined that its benefits do not outweigh its costs and rate impacts.

As this order issues, the legislature is considering alternatives to traditional rate-of-return regulation. States are studying how to restructure the electric industry. The FERC is aggressively promoting comparability in wholesale transmission access and wheeling. In the West, regions and subregions are forming transmission groups to manage cooperative arrangements for wheeling power across systems. The federal marketing agencies face the first real change in how they do business since their formation.

Decoupling is not consistent with these and other movements toward greater competition, because decoupling insulates a utility from lost margins that result from lost retail sales. For example, if PGE should lose a customer to self-generation, decoupling would restore those lost margins to PGE. I believe these business risks are more appropriately left with PGE than shifted to the ratepayers through decoupling. PGE is better situated to manage these risks and compete on price or service quality whenever necessary. As the market becomes more competitive and firms compete for their share of energy sales, it does not seem apposite to institute a policy that essentially guarantees the utility a fixed level of sales and resulting margins. The standard competitive framework does not guarantee each company a fixed sales level and resulting margins. Rather, the sales level and profitability of a company is directly related to how well and efficiently the company satisfies the needs of its customers.

The time for decoupling has passed. The changes in energy markets, the burdens and difficulty in administration, and PGE's reluctance all militate against use of this mechanism to meet the Commission's goals of promoting energy efficiency. Decoupling should not be implemented.

Nevertheless, the goal of using energy resources efficiently and wisely remains. The goal of diversifying the resource base remains. It is just that circumstances have loosened regulators' grip on traditional levers. We must find other ways of meeting the need and the challenge. Decoupling is not the solution. The doubts and questions voiced in my dissent in Order No. 92-1673 have not been answered. It is time to consider other forms of regulation more attuned to the evolving energy marketplace.

PUBLIC UTILITY COMMISSION OF OREGON

Joan H. Smith

Joan H. Smith
Chairman

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 this order. The request must comply with the requirements of OAR 860-14-095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-13-070(2)(a). A party may appeal this order to a court pursuant to ORS 756.580.

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UE 88

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10/27/94

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 88

In the Matter of the Revised)
Tariff Schedules for Electric)
Service in Oregon Filed by) STIPULATION
PORTLAND GENERAL ELECTRIC)
COMPANY - Advice No. 93-26)

RECITALS

1. On November 8, 1993, Portland General Electric Company filed for a general rate change affecting its price schedules in Advice No. 93-26. Docket UE-88 is the proceeding for resolution of the issues in Advice No. 93-26.

2. The new price schedules are based on PGE's expected revenue requirement for a two-year test period covering 1995 and 1996. On November 8, 1993, PGE filed testimony, exhibits, and workpapers in support of its 1995 and 1996 revenue requirements (the November 8 filing).

3. On March 21, 1994, the Staff of the Public Utility Commission of Oregon (Staff) filed a motion to amend the schedule and to bifurcate. In this motion, Staff requested that issues considered by the Commission in the DR 10 proceeding related to PGE's Trojan Nuclear Plant (Trojan) and cost of capital be considered apart from all other issues. The Hearings Officers granted the Motion to Bifurcate on May 3, 1994 and established a schedule for the Trojan-related issues and cost of capital. For purposes of this Stipulation, Phase I refers to proceedings

related to issues other than Trojan and cost of capital, Phase II refers to the proceedings related to Trojan and cost of capital. This stipulation primarily covers Phase I issues.

4. Pursuant to the Hearings Officers' Memorandum and Ruling of December 15, 1993, the Staff filed for discussion at the Phase I settlement conferences, a "Staff Issues List" dated March 25, 1994. The Staff Issues List identified Phase I adjustments Staff proposed to PGE's requested revenue requirements components for test years 1995 and 1996 as set forth in the November 8 filing.

5. On May 10, 1994, PGE filed supplemental testimony concerning power cost issues. On May 13, 1994, Staff filed testimony, exhibits, and workpapers in support of its position concerning PGE's 1995 and 1996 Phase I revenue requirements. On June 9, 1994, Staff filed supplemental testimony concerning power cost issues.

TERMS OF STIPULATION

WHEREFORE, PGE and Staff hereby agree to the following with respect to PGE's requested revenue requirements, rate spread, and rate design as set forth in the November 8 filing. Designations beginning with "S-" are from the March 25, 1994 Staff Issues List.

1. PGE and Staff agree that the revenue sensitive factors shown in Attachment 1, attached to and made a part of

this stipulation, should be used in the determination of PGE's required revenues for test years 1995 and 1996. PGE and Staff further agree that adjustments to test years' expenses, including tax deductible interest, should have related tax effects calculated using the following effective rates: Federal, 35%; State, 6.672%; Environmental, 0.12%.

PGE and Staff also agree that a factor of 4.55% should be applied to all operating expense and tax adjustments to the November 8 filing data to derive the appropriate revisions to the working cash rate base allowance.

Corrections to the November 8 filing (S-1 through S-11)

2. S-1. PGE will decrease its operation and maintenance (O&M) expenses in 1995 by $299,000 and in 1996 by $628,000 and will decrease taxes other than income in 1995 by $7,000 and in 1996 by $15,000 to correct an error in the November 8 filing. The November 8 filing mistakenly and inappropriately included a double inflation of PGC direct charges to PGE.

3. S-2. PGE deferred the savings from terminating its membership in EPRI in October 1993 pursuant to Order No. 91-186. Rather than amortize the savings of $1,715,000 in 1995 and $1,717,000 in 1996 through Docket UE-88, PGE will file to amortize them simultaneously with its 1995 SAVE rate changes. No revision of November 8 filing data is required.

4. S-3. PGE will decrease its requested O&M expenses in 1995 by $23,000 and in 1996 by $24,000 to remove Category "C" advertising mistakenly and inappropriately included in the November 8 filing.

5. S-4. PGE will decrease its requested O&M expenses in 1995 by $1,230,000 and in 1996 by $1,488,000 to correct an error in the calculation of costs for the retirement savings plan. PGE inadvertently and inappropriately escalated the matching fund expense for inflation twice and did not reduce expense to reflect a tax deduction for stock dividends used to pay off ESOP debt.

6. S-5. PGE will decrease its requested O&M expenses in 1995 by $1,497,000 and in 1996 by $160,000 to reduce legal expenses that were overstated in the November 8 filing.

7. S-6. PGE will decrease its requested O&M expenses in 1995 by $314,000 and in 1996 by $702,000 to reflect a reduction in the escalation rate of its active health and dental costs from 15 percent to 12 percent per year.

8. S-7. PGE will increase its requested other revenues at current rates in 1995 by $687,000 and in 1996 by $688,000 to refund to customers the 1990 through 1994 accruals for carrying costs originally expensed on PGE's books but subsequently charged to Trojan and Boardman co-owners. In addition, PGE will decrease O&M expenses in 1995 by $73,000 and in 1996 by $71,000 to reflect ongoing charges to co-owners.

9. S-8. PGE will increase its requested O&M expenses

in 1995 by $1,870,000 and in 1996 by $2,953,000 to correct service provider costs that the November 8 filing understated primarily because World Trade Center rent and facility costs were charged to a deferral account and not allocated to appropriate expense accounts. The November 8 filing service provider budgets were also understated because they were preliminary and were not escalated for inflation.

10. S-9. PGE will increase its requested net utility plant in 1995 by $438,000 and in 1996 by $414,000 to reflect an inclusion in rate base of tenant improvements to the conference rooms in Building 2 of the World Trade Center. These tenant improvements are consistent with associated revenues included in the November 8 filing.

11. S-10. PGE will increase its requested O&M expenses in 1995 by $692,000 and in 1996 by $808,000 to include interest on the Managers' and Directors' Deferred Compensation Plan balances that was excluded from the pool of PGC costs billed to PGE per the November 8 filing.

12. S-11. PGE will decrease its requested income tax expense in 1995 by $192,000 and in 1996 by $608,000 and increase accumulated deferred income taxes in 1995 by $1,478,000 and in 1996 by $3,483,000 to correct several errors discovered in the calculation of income taxes included in the November 8 filing.

<u>Adjustments to the November 8 filing (S-12 through S-44)</u>

13. S-12. PGE will change its requested revenue requirement elements as shown below to reflect an increase in anticipated loads resulting from updating PGE's load forecast model with more recent economic data.

	1995	1996
Sales to consumers	$4,392,000	$1,854,000
Net variable power costs	$2,126,000	$1,021,000
Distribution operation and maintenance	$ 260,000	$ 232,000
Depreciation	$ 85,000	$ 75,000
Property taxes	$ 33,000	$ 29,000
Utility plant	$2,135,000	$1,863,000
Accumulated depreciation	$(85,000)	$(75,000)

The parties agree to include an estimate for variable power costs but do not agree on the amount. This can be calculated following a final decision in Issue S-13. The new load forecast includes the Smurfit displacement loads identified by Staff.

14. S-13. No agreement has been reached on appropriate test years' variable power costs.

15. S-14. PGE will increase its requested other operating revenues in 1995 by $1,574,000 and in 1996 by $1,609,000 to reflect revenues from NSF/reconnect/field service fees, temporary connections, billing job profits, and the BPA irrigation discount inadvertently and inappropriately excluded from the November 8 filing. No agreement has been reached on appropriate revenues from operation of the Energy Resource Cente

(ERC).

16. S-15. No agreement has been reached on appropriate test years' employee wage and salary levels.

17. S-16. PGE will decrease its requested O&M expenses in 1995 by $3,745,000 and in 1996 by $3,861,000 and taxes other than income in 1995 by $412,000 and in 1996 by $425,000 to reflect removal of some incentive pay. Reductions equal 50 percent of the Our Teamworks program costs, 75 percent of the non-officer Annual Cash Incentive (ACI) Program expenses and 100 percent of the officer ACI Program expenses.

18. S-17. PGE will decrease its requested O&M expenses in 1995 by $1,957,000 and in 1996 by $2,046,000 to remove from the November 8 filing those costs associated with the supplemental executive retirement program. In addition, PGE will increase rate base in 1995 by $1,200,000 and in 1996 by $2,389,000 to reflect reduced accumulated unfunded liabilities for which customers have paid.

19. S-18. PGE will decrease its requested O&M expenses in 1995 by $1,845,000 and in 1996 by $2,172,000 and increase rate base in 1995 by $477,000 and in 1996 by $542,000 to remove from the November 8 filing all elements associated with the managers' deferred compensation program.

20. S-19. PGE will decrease its requested O&M expenses in 1995 by $204,000 and in 1996 by $194,000 to remove from the November 8 filing all costs associated with the directors' deferred compensation and pension plans.

21. S-20. PGE will decrease its requested O&M expenses in 1995 by $314,000 and in 1996 by $748,000 to reflect a reduction from the November 8 filing of costs associated with medical/dental insurance. The change results from a reduction in the annual escalation factor from 12 percent to 7 percent. In addition, rate base will decrease by $65,000 in 1995 and $276,000 in 1996 to reflect the related capitalized medical costs' impact on utility plant in service.

22. S-21. PGE's November 8 filing includes O&M expenses associated with membership in the Electric Power Research Institute (EPRI). The parties agree that $1.782 million for 1995 and $1.879 million for 1996, in expenses related to EPRI membership may be included in rates subject to the conditions outlined below.

PGE plans to rejoin EPRI on January 1, 1995, if EPRI revises its fee structure to allow varying levels of participation and targeted research. If PGE does not rejoin EPRI on January 1, 1995, because EPRI does not revise its fee structure or for some other reason, or if the annual EPRI expenses are less than the amounts specified above, PGE will defer for refund to customers the revenues associated with the EPRI-related expenses included in UE 88, except for revenues associated with such amounts as PGE demonstrates it has spent pursuant to the following criteria:

A. The expenditure is for outside services or materials only. No PGE labor or overheads will be included.

B. The requesting department shows that the expenditure for outside services or materials is incremental to amounts budgeted for such items in the test period.

C. The requesting department demonstrates that the cost incurred is a direct result of not being a member of EPRI; i.e., the project or research was previously an EPRI project or EPRI provided similar research or support.

D. The requesting department prepares a statement on the need for the research expenditure and the desired result. Only expenditures related to distinct and tangible research activities will be accepted. Expenditures related to other more general activities, including, but not limited to, strategic planning, performance measurement, reporting processes, corporate strategy, budgeting, and forecasting are not acceptable.

The decision as to what qualifies as an acceptable expenditure in this regard will reside solely with the Commission and its staff.

No later than March 1 of 1996 and 1997, the Company will submit a report as to the expenses it believes qualify for treatment under this Stipulation for the preceding year. Any amounts falling short of the annual sums specified above will be deferred, as of year end, for future disposition by the Commission. Interest on deferrals will accrue at the authorized rate of return in UE 88 with one-half years' interest added to each vintage year's initial accrual.

This procedure will continue until the Commission issues a rate order in the general rate proceeding immediately subsequent to UE 88.

23. S-22. PGE will decrease its requested O&M expenses in 1995 by $1,073,000 and in 1996 by $1,594,000 to reflect the application of WEFA Fourth Quarter inflation forecasts to PGE's operation and maintenance expenses in place of the WEFA June inflation forecasts used in the November 8 filing.

24. S-23. PGE will decrease its requested O&M expenses in 1995 by $103,000 and in 1996 by $108,000 to remove from the November 8 filing certain non-labor expenses forecasted in the Customer Accounting area.

25. S-24. PGE will decrease its requested O&M expenses in 1995 by $278,000 and in 1996 by $286,000 and taxes other than income in 1995 by $15,000 and in 1996 by $16,000 to remove from the November 8 filing expenses associated with its Community Development program.

26. S-25. PGE will decrease its requested O&M expenses in 1995 by $203,000 and in 1996 by $212,000 and taxes other than income in 1995 by $15,000 and in 1996 by $16,000 to reduce the forecasted cost of PGE's market information function.

27. S-26. For 1995, PGE will decrease its requested net utility plant $687,000. For 1996, PGE will decrease its requested net utility plant by $7,421,000 , O&M expense by $700,000, and amortization expense by $2,562,000 to reflect a reduction in the forecasted rate base for the CS/2 customer information system, an on-line date of July 1, 1996, rather than January 1 as forecast in the November 8 filing, amortization over ten years rather than five years, and a forecast decrease in operation and maintenance costs following implementation of CS/2. As PGE receives revenue from the sale of CS/2 to other utilities, it will credit 91.2 percent to the unamortized balance of CS/2 and 8.8 percent to other income and deductions.

28. S-27 through S-30. No agreement has been reached on appropriate test years' category A advertising, power smart expenses, HVEA program expense or Energy Resource Center (ERC) expenses.

29. S-31. PGE will revise its requested revenue requirement elements as follows to include a forecast of energy efficiency investment and savings in each year in base prices,

rather than Schedule 103 as proposed by PGE.

	1995	1996
Sales to consumers	$(4,086,000)	$(12,226,000)
Other operating revenues	$ 254,000	$ 244,000
Net variable power costs	$(4,059,000)	$(8,576,000)
Other operation and maintenance	$ 1,160,000	$ 3,128,000
Energy efficiency investment	$19,916,000	$ 47,856,000

The parties support continued use of an energy efficiency investment true-up mechanism, such as presently exists in Schedule 101, and agree that such mechanism is appropriate to implement a change in the overall energy efficiency amortization period, should PGE propose such and the Commission approve that proposal. The parties agree to include an estimate for variable power costs but do not agree on the amount. This can be calculated following a final decision on Issue S-13.

30. S-32 and S-33. No agreement has been reached on appropriate test years' Portland General Corporation allocations or equity issuance cost treatment.

31. S-34. PGE will decrease its requested taxes other than income in 1995 by $19,000 and in 1996 by $379,000 to reflect a forecast effective payroll tax rate of 11 percent in both test years. In addition, PGE will reduce its requested rate base element for utility plant in service by $4,000 in 1995 and by $81,000 in 1996 to reflect reduced capitalized payroll taxes.

32. S-35. The parties will address the tax effect of any change in PGE's rate of return from the November 8 filing in the next phase of the case.

33. S-36. PGE will decrease its requested non-fuel materials and supplies investment in 1995 by $553,000 and in 1996 by $1,089,000 to reflect the application of WEFA Fourth Quarter inflation forecasts to PGE's materials and supplies rate base balances in place of the WEFA June inflation forecasts used in the November 8 filing.

34. S-37. PGE will withdraw proposed Schedule 107. PGE will reduce requested amortization credits in 1995 by $36,707,000 and in 1996 by $36,417,000. PGE will also increase the Boardman gain rate base credit in 1995 by $18,354,000 and in 1996 by $54,916,000 as well as increase accumulated deferred income taxes in 1995 by $7,233,000 and in 1996 by $22,149,000.

35. S-38. No agreement has been reached on appropriate incremental power cost calculations for the decoupling mechanism.

36. S-39. PGE will use the weather-normalization coefficients used in the Docket UE-88 load forecast to weather-adjust actual revenues during the decoupling period. The monthly weather-adjusted "actual" sales (WAAS) for the decoupling period will be calculated using the sales model developed by PGE. The weather-adjustment process is implemented by running the sales model at "actual" weather conditions and at "normal" weather conditions. The difference between these two model runs yields

the "weather-adjustment" quantities. For example, during the heating season colder weather would result in kWh quantities being subtracted from actual or recorded sales and warmer weather would lead to kWh quantities being added to actual sales, all else being equal. The "normal" weather values are defined as averages over the most recent 30 year period. The weather coefficients are specified in Attachment 2.

37. S-40. PGE and Staff will use their best efforts to obtain appropriate treatment of decoupling adjustments by the Bonneville Power Administration (BPA) in the determination of average system cost for purposes of the Residential Exchange Program. Regardless of the treatment adopted by BPA, however, PGE will pass through to residential and farm customers all Residential Exchange Program benefits actually received, no less and no more.

38. S-41. No agreement has been reached on appropriate corrections to PGE's marginal cost study and appropriate rate spread policy.

39. S-42. As a result of withdrawing proposed Schedules 103 (Issue S-31) and 107 (Issue S-37), PGE will include 1995/1996 energy efficiency costs and refund of the Boardman gain in overall revenue requirements for rate spread purposes.

40. S-43. The revenue adjustment of $540,000 per year for an interruptible service tariff will be included only under the following conditions:

1. PGE files a tariff for interruptible service by August 1, 1994, with a copy to all UE-88 parties.

2. PGE demonstrates in its filing or during subsequent review of the filing that a) all customers will benefit from the offer of interruptible service, and b) the offer will reduce net revenues by at least $540,000 a year. The net revenue estimate must recognize new sales (not just the shift of existing sales from firm to interruptible service) and cost savings to the company.

3. The Commission decides before October 1, 1994 to allow the tariff for interruptible service to go into effect.

The increase in expected annual displacement sales to Smurfit to 30,000 mWh is recognized in the load forecast adjustment (Issue S-12).

41. S-44. With the exception of proposed schedules 103, 107, and the increase to the customer charge on Schedule 7, PGE will implement its proposed overall rate design described in PGE Exhibit 800. Minor deviations from PGE's proposed rate design may be necessary to achieve a smooth transition between rate schedules. In addition, in implementing the demand charge changes on Schedules 31/32, 82/83, and 89, PGE may propose to phase-in the change, provided that this is done without affecting the overall rate spread between classes and is revenue neutral. Furthermore, the shifts from energy to demand will be limited,

however, so that energy charges for any affected schedule remain at or above the marginal cost of energy.

The residential customer charge will be set based on the revenue increase allocated to Schedule 7 as follows:

Schedule 7 Increase*	Customer Charge
Less than $5 million	$5.00
$5 to $10 million	$5.50
Over $10 million	$6.00

* Based on a two year test period. For a one-year test period, the allocated increase values should be halved.

The energy charges for the two blocks of Schedule 7 will then be adjusted on an equal percentage basis to achieve the total allocated revenue requirement, except that the tailblock rate will not be reduced if there is an overall increase.

42. Staff and PGE agree that a change in accounting method whereby depreciation is simplified for the specific PGE general plant accounts listed below is appropriate.

- 39100 - Office furniture and equipment
- 39102 - Computer and office equipment (excludes mainframe)
- 39300 - Stores equipment
- 39400 - Tools, shop, and garage equipment
- 39706 - Cellular phones, mobile phones, and pagers
- 39800 - Miscellaneous equipment

Under the revised accounting method, records will no longer be maintained at the individual retirement unit level.

Instead, the Continuing Property Record will be maintained at a vintage level with the entire vintage retired from the record upon reaching the authorized depreciable life.

These accounts comprise a small percentage (1.7%) of total net plant investment, are relatively inexpensive, and are considered portable and are frequently relocated. Because of their size and mobility they are very difficult to track and maintain valid location, retirement, and transfer records. The Commission has previously approved this method for Washington Water Power.

The undepreciated cost of pre-1995 assets will be depreciated over the remaining depreciation lives approved in UM-541, and then retired from plant in-service in total along with associated depreciation reserve amounts. The depreciation expense to be implemented with a UE-88 general rate case order will be calculated using a whole-life equivalent depreciation rate. The broad group depreciation rates will assume no retirement dispersion. Depreciation of post-1994 assets will begin the month after the job is closed to plant in-service. The depreciation reserve will be maintained by vintage, and depreciation in the year of retirement will be calculated by subtracting the depreciation reserve balance from the vintage plant in-service balance.

Ongoing review and future revisions of the depreciation lives and salvage rates will continue to be authorized by the Commission based on input from Staff and the Company. The

Company will provide information to support any potential change to the stipulated depreciation lives and salvage rates as part of future depreciation studies. Such support will be the best available information from such sources as engineering estimates, tax lives, and/or industry surveys.

This change in accounting method will not precipitate a change in PGE's revenue requirement. The only differences between the two methodologies is that the revised method will simplify the process of tracking and reporting net asset values and will create a change in the way retirements are recorded during the asset service lives.

43. PGE agrees to withdraw its application for deferred accounting docketed UM-444 coincident with a Commission order in this proceeding authorizing full recovery of and on the Trojan steam generator analysis, plugging, and sleeving costs referenced in Commission Order 92-1062 and PGE's UM-494 request for an accounting order.

44. Staff and PGE agree that these stipulations are reasonable under the standards and perspectives usually applied in a general rate proceeding.

45. Staff and PGE have entered into these stipulations in good faith. Cost recovery considerations associated with the Trojan Nuclear Plant, however, particularly with respect to the issues raised in Commission Order No. 93-1117, will lead to further assessment of the Trojan and cost of capital elements of PGE's required revenues. Should Staff propose adjustments to

PGE's 1995 and/or 1996 revenue requirements in Phase II of Docket UE-88, none of the items stipulated above will prevent PGE from presenting any evidence in rebuttal to issues raised by Staff in Phase II it deems necessary.

Furthermore, if Staff or PGE proposes changes in the revenue requirements for any of the items covered by this Stipulation which are inconsistent with the terms of the Stipulation during the Phase II proceeding, both Staff and PGE reserve the right to be released from the terms of any or all elements of this Stipulation.

Nevertheless, it is the intent of the parties, unless either exercises the release option previously described, that Phase I stipulations remain in effect should the Commission reject further adjustments Staff may propose in Phase II of Docket UE-88.

If the Commission rejects any part of this Stipulation, the stipulating parties may withdraw from the whole Stipulation unless the parties agree to the modification. To the extent any party proposes changes that are inconsistent with the terms of one or more issues in this Stipulation, such changes shall not disturb any other issues addressed in the Stipulation. To the extent the Stipulation is partially modified or withdrawn, neither the Stipulation nor any information obtained in settlement discussions may be used as evidence against any party.

46. This Stipulation shall be entered in the record in Phase I of this proceeding as evidence pursuant to OAR 860-14-

085(1). PGE and Staff agree that all of the testimony filed in Phase I of this docket shall be entered in the record of proceeding. The parties agree to waive cross-examination of the other parties' testimony on items included in this Stipulation. If any issue covered by this Stipulation is challenged by someone not a party to this Stipulation, then the parties agree to support and argue in good faith for the Commission's approval of all of the provisions of this Stipulation.

47. Staff and PGE have executed this Stipulation to resolve identified issues in Phase I of this proceeding. Neither Staff nor PGE shall be deemed to have agreed that this Stipulation is appropriate for resolving issues in any other proceeding except for Docket UM-444 (see item 43 above). Neither Staff nor PGE shall be deemed to have accepted or consented to the principles, methods or theories employed in arriving at this Stipulation.

EXECUTED this 1st day of July, 1994.

Paul A. Graham
Paul A. Graham
Attorney for the Staff of the
Oregon Public Utility Commission

Randall W. Childress
Attorney for
Portland General Electric Company

Attachment 1

PORTLAND GENERAL ELECTRIC CO.
General Rate Case Stipulation - UE 88
(000)

REVENUE SENSITIVE COSTS	
Revenues	1.00000
O&M - Uncollectibles/Advert.OPUC*	0.00555
Other Taxes-Franchise	0.02100
Short-Term Interest	0.00000
Other Taxes	0.00000
State Taxable Income	0.97345
State Income Tax @ 6.672%**	0.06495
Federal Taxable Income	0.90850
Federal Income Tax @ 35%	0.31798
ITC	0.00000
Current FIT	0.31798
ITC Adjustment/Env. Tax	0.00109
Total Income Taxes	0.38401
Total Revenue Sensitive Costs	0.41056
Utility Operating Income	0.58944
Net-to-Gross Factor	1.69654

* Uncollectible Rate	0.00230
Advertising Allow.	0.00125
OPUC Fee	<u>0.00200</u>
Total	0.00555

** State Income Tax	
Montana (.0675*.050008)	0.00338
Oregon (.0660*.959764)	<u>0.06334</u>
Total	0.06672

PGE Weather Adjustment Model (WAM) Weather Variables Coefficients

RESIDENTIAL SECTOR EQUATIONS							
	Winter Months Temperature[1]	Spring Months Temperature[1]	Swing Months Temperature	Summer Months Temperature	Cooling Degree Days (@75°F)	Wind Speed	Minutes of Sunshine
Single-Family Heat	-824.49	-712.51	-25.72	-11.96	3.96	17.76	-0.0059
Single-Family NonHeat	-139.03	-132.58	- 2.67		1.52	6.26	-0.0026
Multi-Family Heat	-660.48	-546.37	-19.38	- 9.56	1.87	12.04	-0.0024
Multi-Family NonHeat	-107.08	- 97.65	- 1.60		1.12	3.47	-0.0017
Mobile Home Heat	-865.35	-694.65	-26.59	-12.32	4.55	21.28	-0.0080
Mobile Home NonHeat	- 41.53	- 29.71	-11.03		2.83	13.20	-0.0060
Other Residential	-1401.34	-1281.34	-37.19		4.61	18.26	-0.0021
COMMERCIAL SECTOR EQUATIONS							
	Winter Months Heating Degree Days (@65°F)	Spring Months Heating Degree Days (@65°F)	Swing Months Heating Degree Days (@65°F)	Cooling Degree Days (@65°F			
Trans., Comm. & Utility	7.74	7.04		17.85			
Department Stores /Malls	9.92	5.84		17.91			
Food Stores	2.29			11.36			
Restaurants	5.07	3.64		18.58			
Other Trade	15.51	14.84		21.77			
Fin., Ins, Real Est. & Offices	19.69	15.32		24.28			
Lodging	6.79	6.50	2.66	5.22			
Other Services	21.42	21.02	4.93	22.98			
Health Services	8.49	2.65		16.74			
Government & Education	20.96	17.45		22.68			
Miscellaneous Commercial	14.46	14.23	3.99	5.74			

[1] square root of temperature

Attachment 2

95-322

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 88

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon Filed by PORTLAND GENERAL ELECTRIC COMPANY - Advice No. 93-26	STIPULATION SUPPLEMENT #1

1. On November 8, 1993, Portland General Electric Company filed for a general rate change affecting its price schedules in Advice No. 93-26. Docket UE-88 is the proceeding for resolution of the issues in Advice No. 93-26.

2. The new price schedules are based on PGE's expected revenue requirement for a two-year test period covering 1995 and 1996. On November 8, 1993, PGE filed testimony, exhibits, and workpapers in support of its 1995 and 1996 revenue requirements (the November 8 filing).

3. On March 21, 1994, the Staff of the Public Utility Commission of Oregon (Staff) filed a motion to amend the schedule and to bifurcate. In this motion, Staff requested that issues considered by the Commission in the DR 10 proceeding related to PGE's Trojan Nuclear Plant (Trojan) and cost of capital be considered apart from all other issues. The Hearings Officers granted the Motion to Bifurcate on May 3, 1994 and established a schedule for the Trojan-related issues and cost of capital. For purposes of this Stipulation, Phase I refers to proceedings related to issues other than Trojan and cost of capital, Phase II

refers to the proceedings related to Trojan and cost of capital. This stipulation primarily covers Phase I issues.

4. Pursuant to the Hearings Officers' Memorandum and Ruling of December 15, 1993, the Staff filed for discussion at the Phase I settlement conferences, a "Staff Issues List" dated March 25, 1994. The Staff Issues List identified Phase I adjustments Staff proposed to PGE's requested revenue requirements components for test years 1995 and 1996 as set forth in the November 8 filing.

5. On July 1, 1994 PGE filed testimony and exhibits (the July 1 Rebuttal) responding to certain issues raised by Staff and other parties.

6. Also on July 1, 1994, PGE and Staff filed a Stipulation describing agreement between them on numerous revenue, expense, and rate base issues identified in the Staff Issues List.

TERMS OF STIPULATION

WHEREFORE, PGE and Staff hereby agree to the following issues in addition to those covered in the July 1 Stipulation. Designations beginning with "S-" are from the March 25, 1994 Staff Issues List.

1. S-14. PGE will increase its requested other operating revenues in 1995 by $75,000 and in 1996 by $75,000 to

reflect revenues from seminars and conferences it may offer through its Energy Resource Center (ERC).

2. S-27. PGE will decrease its operation and maintenance (O&M) expenses in 1995 by $105,790 and in 1996 by $373,578 to remove from the November 8 filing certain Category "A" advertising expenses. These amounts are not subject to further adjustment for any change in the amount of advertising set as presumptively reasonable by operation of the formula in OAR 860-26-022(3)(a) on final revenues established in this Docket.

3. S-28. PGE will decrease its O&M expenses in 1995 by $107,619 and in 1996 by $112,075 to remove from the November 8 filing certain expenses associated with the non-advertising costs of PGE's Power Smart program.

4. S-30. PGE will decrease its O&M expenses in 1995 by $211,106 and in 1996 by $211,106 to remove from the November 8 filing the lease costs associated with the Tualatin ERC facility.

5. S-33. Staff and PGE agree to stipulate into the record in this proceeding the nine pages attached to this Stipulation Supplement 1 as Attachment 1.

6. PGE will withdraw from its July 1 Rebuttal PGE Exhibit 1316 in total and from PGE Exhibit 1300 the sentences on page 22, lines 15 through 17, beginning with the words "Exhibit 1316 describes . . . ." In addition, PGE will revise PGE Exhibit

1300, page 22, line 18 to replace the word "results" with the word "test".

7. PGE and Staff agree that PGE may add to PGE Exhibit 1302 the pages attached to this Stipulation Supplement 1 as Attachments 2 and 3 and may revise PGE Exhibit 1300, page 6, lines 2 through 3 to replace the sentence "PGE Exhibit 1302 contains several ads produced by Alberta Power on various electrical applications that increase the use of electricity" with the sentence "PGE Exhibit 1302 contains several ads produced by Canadian utilities on various electrical applications, some of which increase the use of electricity."

8. Staff and PGE agree that, if the Commission implements the decoupling mechanism proposed in this docket for PGE, that mechanism will not take effect until, and PGE will not calculate the decoupling adjustment for any months prior to, the effective date of tariffs in this proceeding. Regardless of the effective date of the tariffs, and thus the decoupling mechanism, PGE will maintain the decoupling periods and filing schedule contemplated by the mechanism. Accordingly, PGE's first decoupling filing would occur August 1, 1995, for the period from the effective date of the tariffs through June 30, 1995. If the amount of any decoupling adjustment is small, PGE may defer the adjustment to its next decoupling filing. Staff and PGE further agree that, with respect to the calculations of revenue under the UE 88 tariffs needed for purposes of amortization of deferred

power costs for the period January 1, 1995 through March 31, 1995, such revenues shall be calculated without weather-adjustment and without the effects of the decoupling mechanism.

9. Staff and PGE agree that this stipulation is reasonable under the standards and perspectives usually applied in a general rate proceeding.

10. Staff and PGE have entered into these stipulations in good faith. Cost recovery considerations associated with the Trojan Nuclear Plant, however, particularly with respect to the issues raised in Commission Order No. 93-1117, will lead to further assessment of the Trojan and cost of capital elements of PGE's required revenues. Should Staff propose adjustments to PGE's 1995 and/or 1996 revenue requirements in Phase II of Docket UE-88, none of the items stipulated above will prevent PGE from presenting any evidence in rebuttal to issues raised by Staff in Phase II it deems necessary.

Furthermore, if Staff or PGE proposes changes in the revenue requirements for any of the items covered by this Stipulation which are inconsistent with the terms of the Stipulation during the Phase II proceeding, both Staff and PGE reserve the right to be released from the terms of any or all elements of this Stipulation.

Nevertheless, it is the intent of the parties, unless either exercises the release option previously described, that Phase I stipulations remain in effect should the Commission reject further adjustments Staff may propose in Phase II of Docket UE-88.

If the Commission rejects any part of this Stipulation, the stipulating parties may withdraw from the whole Stipulation unless the parties agree to the modification. To the extent any party proposes changes that are inconsistent with the terms of one or more issues in this Stipulation, such changes shall not disturb any other issues addressed in the Stipulation. To the extent the Stipulation is partially modified or withdrawn, neither the Stipulation nor any information obtained in settlement discussions may be used as evidence against any party.

11. This Stipulation shall be entered in the record in Phase I of this proceeding as evidence pursuant to OAR 860-14-085(1). PGE and Staff agree that all of the testimony filed in Phase I of this docket shall be entered in the record of proceeding. If any issue covered by this Stipulation is challenged by someone not a party to this Stipulation, then the parties agree to support and argue in good faith for the Commission's approval of all of the provisions of this Stipulation.

12. Staff and PGE have executed this Stipulation to resolve identified issues in Phase I of this proceeding. Neither Staff nor PGE shall be deemed to have agreed that this Stipulation is appropriate for resolving issues in any other proceeding. Neither Staff nor PGE shall be deemed to have

accepted or consented to the principles, methods or theories employed in arriving at this Stipulation.

EXECUTED this 14th day of July, 1994.

Michael T.

Michael T. Weirich
Attorney for the Staff of the
Oregon Public Utility Commission

Melinda Horgan
Attorney for
Portland General Electric Company

TO: Janice Fulker
Oregon Public Utility Commission

May 22, 1990

FROM: Warren Winter, PGE
Manager - Economic Regulation

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MAY 1990
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PORTLAND GENERAL ELECTRIC COMPANY
GENERAL FILING UE-79
PGE RESPONSE TO OPUC Staff Data Requests No. 60

Request 60-1

When does PGE expect to achieve a capital structure containing 46 percent common equity, as recommended by Warren Winter on page 50 of PGE's Exhibit 3D? Provide all workpapers demonstrating the achievement of the recommended capital structure.

Response

PGE expects to achieve a capital structure containing 46 percent common equity by year end 1993. Attached is a spreadsheet detailing the common equity forecast for year end 1991 to 1993. The analysis assumes the following: (1) year end 1991 values are based upon the PGE forecast provided in response to OPUC Data Request No. 28; (2) annual earnings on common equity are conservatively based on prior year end common equity as opposed to an average; (3) capital expenditures are 100 percent internally funded (which is consistent with PGE's financial strategy); (4) percentage of utility capital is based on 1991 general filing ratio of ratebase to total capital; (5) utility ROE remains constant at 13.5 percent; (6) non-utility ROE is based on the earnings power of the WNP3 exchange contract; (7) debt remains constant; (8) preferred is reduced at the rate of $1.8 million a year; and (9) the annual dividend remains constant at $1.20 per share.

A. Exhibit 3D-10, Cost of Preferred Stock, shows the amount and the effective cost of the Company's outstanding preferred stock for the test period. Preferred stock is shown by issue. No new issues are projected through the 1991 test year. The calculation of the outstanding balances is based on a 12-month average of the average amounts outstanding during the test period. The effective rates represent the internal rate of return of the cash flows associated with each preferred issue. All preferred stock issues, except for the 8.875% Series and the 8.10% series are perpetual issues. The total cost of the preferred issues during the test period is 8.632%.

Common Equity Cost

Q. What is PGE's amount and cost for common equity?

A. The amount of average common equity for the 1991 test year is based on a target of 46% of total capitalization. The market-required return on common equity is discussed in the testimony of Mr. Lyman.

Q. Please explain why PGE has adopted a 46 percent common equity target.

A. The average common equity level for "A"-rated electric utilities is currently 43 to 44% of total capitalization. However, there is a wide spread about this average which recognizes unique company characteristics or circumstances. PGE's earnings are subject to higher volatility than the average A-rated utility. As a result, we have decided that PGE should be on the higher end of the average equity capitalization in order to maintain a sound A-rating. An A-rating is important because it gives us access to debt capital at a lower cost.

Q. Why are PGE's earnings subject to higher volatility?

A. PGE's earnings are more volatile due to its operating characteristics. Under normal circumstances, we have very low variable power costs for a large portion of our energy because of the large hydro base and low cost of nuclear fuel. These benefits of normal operations are passed to customers. Without a power cost adjustment mechanism, disruptions to these low cost supplies can cause us to incur a higher cost for generating or buying replacement power from coal and gas fired plants. We pay for these higher costs by reducing retained earnings. Furthermore, assuming critical water conditions in 1991, we do not project an excess of PGE resources over PGE load for the test year. In the absence of a power cost adjustment mechanism, the potential of critical water increases PGE's financial risk.

Q. What steps is the Company taking to reach the 46% equity level?

A. PGE's common equity at December 31, 1989, after the $89 million reduction for the establishment of a reserve (largely for contested issues currently before the court), was 40%. In order to restore PGE's earnings power and improve its debt coverage ratios[4], Portland General Corporation has reduced its annual common dividend from $1.96 per share to $1.20. In addition, PGE may not pay a dividend to PGC before the fourth quarter of 1990. These two actions will accelerate the restoration of retained earnings at PGE and, thus, common equity. By the end of 1991, in conjunction with the revenue increase requested and dividend management to PGC, PGE will achieve a common equity percentage of between 44 and 46%.

Q. Has PGE been regulated based on a target common equity capitalization structure in the past?

A. In effect, yes. In past cases, our actual structure was not sufficiently different from the desired target that it was an issue. In effect, we were regulated based on a target capital structure. Our goal is to close the gap between actual and desired common equity capitalization as rapidly as is practical. In this case, we are filing with a "normalized"

---

[4] Coverage ratios are important indicators used by credit analysts and rating agencies to assess our financial health and ability to meet debt interest and preferred dividend obligations.

capital structure. We have and are taking some strong steps to restore the financial health of the Company.

Composite Cost of Capital

Q. Please explain Exhibit 3D-11 showing the composite cost of capital.

A. Exhibit 3D-11, Composite Cost of Capital, shows the calculation of cost of capital for PGE during the test period. The average amount and costs of long-term debt and preferred stock were taken from Exhibits 3D-9 and 3D-10, respectively. The average common stock equity balance assumes the targeted 46% of total capitalization target and a market-required return on common equity of 13.5%. The resulting cost of capital for the test period is 11.099%.

95-322

PGE Exhibit 1
2-2D
3-3B
4-4E
5-5C
6-6B
7-7B
8-8E

JAN 1983
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BEFORE THE PUBLIC UTILITY COMMISSIONER
OF THE STATE OF OREGON

PORTLAND GENERAL ELECTRIC COMPANY

Testimony and Exhibits of

Charles L. Heinrich
Warren E. Winter
Charles E. Allcock
Larry A. Soderquist
N. Richard King
James N. Woodcock
Robert F. McCullough
James E. Baggenstos

January 10, 198

PGE Exhibit 6
Witness: J. N. Woodcock

fourth quarter of 1983 and preferred stock in the first or second quarter of 1984. The timing and amount of these equity issues will depend on construction expenditures, financial markets, and, in the case of common stock, the ratio of market value to book value.

Q. What other financing options are under consideration?

A. In 1981, the Company financed its share of the Colstrip project's pollution control equipment by issuing $80 million of 3-year pollution control bonds. These bonds must be refinanced on a long-term basis. We will consider this refinancing if market conditions permit.

Q. Does the timing and amount of rate relief received in 1983 affect the Company's financial picture?

A. Yes. Interim rate relief would have a positive effect on PGE's financial picture, including increased cash flow and earnings. Increased earnings could result in a higher market price for the Company's common stock. If this were to happen, the planned common stock sale would improve the common equity ratio with the issuance of less shares.

Delay in rate relief may require additional external financing. These funds most likely would be obtained from our short-term credit agreements under which we presently have a total of $160 million available.

Q. Would you please discuss the Trojan fuel financing and bank credit agreements.

A. The Trojan fuel agreement was arranged primarily because

PGE Exhibit 8
Witness: J. H. Baggenstos

A. Exhibit 8B, Cost of Long-Term Debt Capital, shows the amount and effective cost of the Company's long-term debt capital for the test period. This exhibit includes the Company's Bank Credit Agreement (commercial paper), Trojan trust notes, and the bond issues projected in the Company's test period financing plan. The average amounts outstanding have been calculated using a 12-month average of the average amounts outstanding each month. The cost of each issue is determined by multiplying the amount outstanding each period by the effective interest rate for each bond issue. The total test period composite cost of long-term debt for PGE is shown in Exhibit 8B to be 10.662 percent.

Q. What is shown on Exhibit 8C?

A. Exhibit 8C shows the cost of the Company's preferred stock by issue. Like long-term debt, the amounts outstanding are based on a 12-month average of the average amounts outstanding each month, and the cost is determined by multiplying the effective rate for each issue times the amount outstanding during the period. The composite cost of preferred stock to PGE during the test period is 12.689 percent.

Q. Could you please summarize the Company's proposed financings during the test period?

A. Yes. The financings (included in my Exhibits 8B, 8C, and average equity in Exhibit 8D) for the test period are:

PGE Exhibit 8
Witness: J. H. Baggenstos

Month of Issue	Type of Security	Total Dollars Raised (Millions)	Interest Rate or Per Share Price*
September 1983	Common Stock	$50	$16.50
March 1984	Preferred Stock	70	13.00%
Various	Colstrip Pollution Control Bonds	19	8.75%

* Market price before issuance expense.

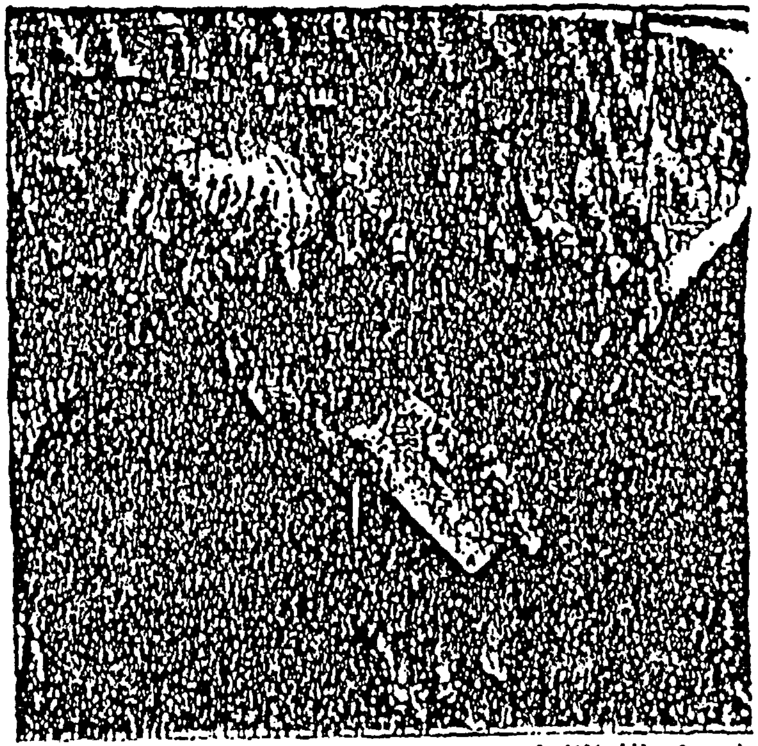
In addition, we plan to raise $25 million from common stock sales through our Common Stock Investment Plan and Employee Stock Purchase Plan.

The Company also intends to issue $80 million of pollution control bonds in April 1984 at 10.25 percent for the purpose of refunding the 8.75 percent issue that is due June 1, 1984. No drawdown from this fund is expected during the test period.

Q. Please explain Exhibit 8D.

A. Exhibit 8D calculates the composite cost of capital for PGE during the test period. The average amount and costs of long-term debt and preferred stock were taken from Exhibits 8B and 8C, respectively. The average common equity has been calculated based upon a 12-month average of the average common equity outstanding each month. This amount includes projected common stock issues during the test period and the increase in average common equity resulting from anticipated retained earnings. The return on common equity is discussed in the testimony of

Straight Talk From The Energy Experts



Question:
What type of heating system is the most popular choice of Newfoundlanders?

Answer: Electric Heat.

Electric heat is popular for many reasons. When all costs are considered, for the average home, electric heat is less expensive than oil or propane.

Electric heat is reliable. If one heater fails, you won't be left out in the cold. And there are no annual service costs or maintenance fees.

Electric heat is comfortable. Today's better quality thermostats will maintain a constant temperature, without noisy burners or blower motors.

Electric heat saves you valuable space because it does not require a furnace, duct work, fuel tank, chimney or vents.

Electric heat is convenient. You have control over individual room temperatures so you're not heating unused areas of the home.

Electric heat is safe. There are no fumes, or combustible fuels inside home and no worry over oil leaks associated clean-up costs.

Call the Power Smart number tod talk to our energy experts. We'll g the facts, without the fine print.

POW
SMA
1800 667
NEWFOUNDLAND

Electric Heat...the smart choice.

SPRING 93

[illegible] Supplement 1
Attachment 2
Page 1 of 1

95-322

DON'T BE "FUELED" BY THE OIL COMPANIES

Converting to oil will COST you money!

*Annual Cost of Electric Heat**

Electric heating cost only	*$1,163.55*

*Annual Cost of Oil Heat***

Furnace payments	*$1,020.00*
Electricity for furnace	*$58.00*
Furnace oil	*$783.52*
Total Oil Heat	*$1,861.52*

CONVERTING TO OIL HEAT WILL COST YOU $697.97 MORE PER YEAR

For the TRUE cost of oil or propane heating, call the energy experts for a free personalized home heating analysis:

STAY ELECTRIC AND SAVE!

*Annual figures based on heating portion of average all electric home - 16,878 kWh electricity - 6.541 cents/kWh.

**Annual figures based on first five years of conversion: $85/month for furnace (includes financing, labour, duct work, chimney and tank); 57.8 M. Btu oil at 35.07 cents/litre; furnace efficiency - 75%.

POWER SMART
1 888 567 8700

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 88

In the Matter of the Revised)
Tariff Schedules for Electric) STIPULATION
Service in Oregon Filed by)
PORTLAND GENERAL ELECTRIC)
COMPANY (Advice No. 93-26))

RECITALS

1. On November 8, 1993, Portland General Electric Company (PGE) filed for a general rate change in Advice No. 93-26. Docket UE 88 is the proceeding for resolution of the issues in advice No. 93-26.

2. On May 3, 1994, the Hearings Officers granted the Staff of the Public Commission of Oregon (Staff) Motion to Bifurcate on, and establish a schedule for, the Trojan-related issues and cost of capital. For purposes of this Stipulation, Phase I refers to proceedings related to issues other than Trojan and cost of capital; Phase II refers to the proceedings related to Trojan and cost of capital. This Stipulation covers Staff Issue S-13, variable power costs and the remaining variable power cost portions of Issues S-12, load forecast, and S-31, energy efficiency from Phase I and Staff's proposed Trojan cost balancing account from Phase II.

3. On July 1, 1994, PGE and Staff entered into a Stipulation regarding agreement on most of the Phase I issues in this proceeding. Staff and PGE did not include the treatment of

variable power costs and left open the variable power cost effects associated with adjustments to PGE's load forecast and energy efficiency forecast included in the July 1, 1994 Stipulation.

4. On July 14, 1994, PGE and Staff entered into Stipulation Supplement 1 regarding additional Phase I matters. Stipulation Supplement 1 did not cover variable power costs.

TERMS OF STIPULATION

WHEREFORE, PGE and Staff hereby agree to the following with respect to PGE's variable power costs and Staff's Trojan Cost Balancing Account proposal:

1. Issue S-13 Variable Power Costs - The parties agree to include in UE 88 base rates variable cost savings expected from the commercial operation of the Coyote Springs generating plant using a forecast in-service date of December 15, 1995.

The December 15th date is the mid-point of the expected range of most likely in-service dates for Coyote Springs: November 8, 1995 through January 21, 1996. November 8th represents the in-service date for which the construction contractor will receive the maximum potential performance incentive. January 21st represents the in-service date beyond which the construction contractor will begin to incur penalties for late performance. Attachment 1 to this Stipulation contains pages from the agreement between PGE and the construction contractor for Coyote Springs that support these dates.

2. The parties agree that, at least 90 days prior to the expected in-service date for Coyote Springs, PGE will file to track the projected capital and fixed costs associated with the plant into the UE 88 base rates. Neither PGE nor any party to this stipulation will propose a change to the variable power cost forecast already reflected in base rates, whether related to Coyote Springs or any other issue, with the exception described in paragraph 3 below. PGE agrees to assume the variable power cost risk associated with a Coyote in-service date later than December 15.

PGE agrees to provide attestation by a corporate officer of Coyote's having met the following minimum requirements prior to the effective date of any Coyote tracker rate increase:

(a) Completion of any operational testing required by the construction contract;

(b) Release of the plant operation to the system dispatcher for full commercial operation; and

(c) Continuous operation at greater than 90 percent of full power for 24 hours.

The parties further agree that the above treatment for Coyote Springs in variable power costs eliminates any need for interest on the "over-collection" in 1995 of 1996 variable power costs that results from the two-year test period associated with decoupling.

3. PGE may file proposed revised rates to address a change in BPA's transmission and power rates at the time such

change occurs through the tracking procedure described below. This procedure is identical to that used to quantify the effects of BPA rate changes on PGE in the variable power cost forecast included in UE 88. PGE will run its Proscreen model, using the same version and inputs which give the identical result of the variable power costs adopted by paragraph 4 of this stipulation, except that PGE will adjust Proscreen for:

(a) Wheeling rates for demand ($/kwmo) and energy (mills/kwh) for all resources covered under the General Transmission Agreement between BPA and PGE dated December 5, 1989, by the percent change in BPA's demand and energy IR wheeling rates; and

(b) The New Resources demand charge for the BPA capacity purchase by the percent change in BPA's NR demand charge.

Since PGE's non-firm purchases and sales are estimated by the Network Economy Interchange (NEI) secondary model in Proscreen, which is independent of BPA's Non-Firm energy rate, no direct adjustment will be made for that rate. However, the NEI may model a different level of secondary purchases and sales as a result of the changes in the BPA rates under (a) and (b), above.

This adjustment is expected to occur at the time of the Coyote tracker described in paragraph 2 above. The basis of the adjustment will be BPA's approved price changes, included in Proscreen as of their effective date. PGE will file proposed revised tariffs reflecting a BPA adjustment at least 30 days prior to the effective date of a Coyote tracker rate change. In the event that BPA's new rates are not approved such that PGE can file at least 30 days prior to a Coyote tracker, the adjustment will occur at the next opportunity PGE has to modify its rates (e.g., at the time of a SAVE tariff adjustment or a decoupling adjustment, if implemented, or some other such time).

Staff agrees that it will support rate changes to reflect BPA increases if such cost increases are material in amount.

4. Tracking rate changes proposed under Sections 2 and 3 of this Stipulation will be subject to a review of PGE's earnings. Accordingly, PGE shall file information to allow an earnings review (which may consist of the most recently filed semi-annual adjusted earnings report to the Commission) with any proposed rate changes.

5. As a result of the stipulations in paragraphs 1 and 3, the parties agree that the following amounts are a reasonable forecast of variable power costs for the test period and include the effects of issues S-12 and S-31 discussed below:

1995:	$304,624,300
1996:	$310,103,700

6. Issue S-12 Load Forecast - Given the forecast of variable power costs for the test period agreed to in paragraph 5 above, the parties agree that the following represents the variable power cost increase associated with the July 1, 1994 stipulation regarding PGE's load forecast:

1995:	$2,554,000
1996:	$1,198,000

7. Issue S-31 Energy Efficiency - Given the forecast of variable power costs for the test period agreed to in paragraph 5 above, the parties agree that the following represents the variable power cost decrease associated with the July 1, 1994 stipulation regarding energy efficiency:

1995:	$(2,656,000)
1996:	$(8,079,000)

8. Trojan Cost Balancing Account - The parties agree that it is appropriate to vary the amortization of the Trojan investment to take into account the actual revenue collected from customers as a result of the Commission's decision in UE 88. The parties therefore agree to a method to modify PGE's actual Trojan amortization expense rather than creating a balancing account. Incremental or decremental amortization expense amounts generated as a result of this stipulation, as described below, will be accumulated in a Trojan Investment Recovery Account (TIRA). The TIRA is designed to provide a procedure to precisely accumulate actual revenue received by PGE as recovery of the Trojan

investment based on amounts authorized by the Commission. As a result, interest will not be added to the TIRA.

The TIRA will operate based on the following:

a) Amounts will be accumulated in the TIRA based on the difference between PGE's actual base calendar revenue from Sales to Ultimate Customers plus miscellaneous operating revenues (base revenue) and PGE's authorized calendar revenue for recovery of Trojan's investment related revenue requirement. PGE's authorized Trojan investment related revenue requirement is defined in d) below.

b) The TIRA will be established as a subaccount to PGE's Trojan Accumulated Amortization Account. The Trojan Accumulated Amortization Account will show the Trojan investment costs recovered from customers based on the Commission authorized rate of recovery. The TIRA will show the incremental or decremental Trojan investment costs recovered as a result of differences between actual and 1995-96 test period forecast calendar revenue. The offsetting entry to the TIRA accumulated amortization subaccount is amortization expense.

c) Actual Trojan investment related calendar revenue will be determined based on a predetermined Trojan Recovery Percentage (TRP) (see section d) multiplied by PGE's total base revenue. For purposes of the TIRA, base revenue is PGE's calendar revenue excluding any other adjustments (i.e., calendar revenue from separate tariffs such as those for SAVE, deferred power cost recoveries, energy efficiency true-up, ballot measure 5 refunds, and the Residential Exchange Program are to be excluded from both actual revenue and test period forecast revenue for purpose of the TIRA).

d) The TRP arising from Docket No. UE 88 will be calculated separately for 1995 and 1996 based on the Commission's final authorized Trojan investment recovery in each year and the following formula:

$$\text{TRP} = \frac{\text{Authorized Trojan Investment Revenue Requirement}}{\text{Total PGE Authorized Revenue Requirement}^{1}}$$

The components of Trojan Investment recovery will be limited to those associated with a return on and of the Trojan investment including related current and deferred tax effects. Elements not to be included in the TRP include the revenue

---

[1] The authorized revenue requirement includes miscellaneous operating revenue.

requirement effects of Trojan related normal operating costs such as transition O&M, property insurance and taxes, and decommissioning expense.

e) For periods subsequent to the end of 1996, until PGE implements a general rate change after December 31, 1996 based on an order of the Commission, PGE will base adjustments to the TIRA on the following differences:

  1) actual Trojan investment related calendar revenue based on application of the 1996 TRP as described in a) through c) above; and,

  2) the 1996 authorized Trojan investment revenue requirement used to calculate the 1996 TRP.

f) When PGE's Trojan related rate base, including the TIRA and any future Trojan capital additions, proceeds from salvage activities, property transfers, and/or tax basis adjustments (all as approved by the Commission), nets to zero, the full Commission authorized investment will have been recovered. Any residual balance, whether debit or credit, will be disposed of only at the direction of the Commission.

g) If decoupling is adopted and implemented as a result of this proceeding, the parties agree that the actual Trojan investment related revenue based on the TRP will not be subject to any decoupling related adjustment. The decoupling mechanism authorized by the Commission, if any, will be modified to eliminate the possibility of duplication with the TIRA.

h) PGE agrees to report the balance in the TIRA within, and as of the end of the period covered by, each semi-annual adjusted results of operations report filed with the Commission.

i) Staff agrees that the TIRA as described herein is a reasonable substitute for the Trojan Cost Balancing Account (TCBA) recommended in testimony and briefed in Docket No. UE 88. Then if the Commission adopts this Stipulation and the TIRA, Staff would withdraw its recommendation for a TCBA.

9. Staff and PGE agree that this stipulation is reasonable under the standards and perspectives usually applied in a general rate proceeding.

10. If the Commission rejects any part of this Stipulation, the stipulating parties may withdraw from the whole Stipulation unless the parties agree to the modification. To the extent any party proposes changes that are inconsistent with the terms of one or more issues in this Stipulation, such changes shall not disturb any other issues addressed in this Stipulation.

To the extent the Stipulation is partially modified or withdrawn, neither the Stipulation nor any information obtained in settlement discussions may be used as evidence against any party.

11. This Stipulation shall be entered in the record in Phase II of this proceeding as evidence pursuant to OAR 860-14-085(1). If any issue covered by this Stipulation is challenged by someone not a party to this Stipulation, then the parties agree to support and argue in good faith for the Commission's approval of all of the provisions of this Stipulation.

12. Staff and PGE have executed this Stipulation to resolve identified issues in this proceeding. Neither Staff nor PGE shall be deemed to have accepted or consented to the principles, methods or theories employed in arriving at this Stipulation.

EXECUTED this 27th day of February, 1995.

Paul A. Graham

Paul A. Graham
Attorney for the Staff of the
Oregon Public Utility Commission

Melinda J. Horgan
Attorney for
Portland General Electric Company

Amendment No. 3
To
Turnkey Engineering, Procurement and Construction Agreement

This Amendment No. 3 to that certain Turnkey Engineering, Procurement and Construction Agreement dated as of August 13, 1993 by and between Portland General Electric Company ("Owner") and Ebasco Constructors Inc. ("Contractor") (the "EPC Contract") is made and entered into as of January 19, 1995.

RECITALS

A. Raytheon Constructors, Inc., a Delaware corporation with offices at 3000 W. MacArthur Boulevard, Santa Ana, California 97204 has been assigned and has assumed all rights and obligations of Ebasco Constructors Inc. as Contractor under the EPC Contract;

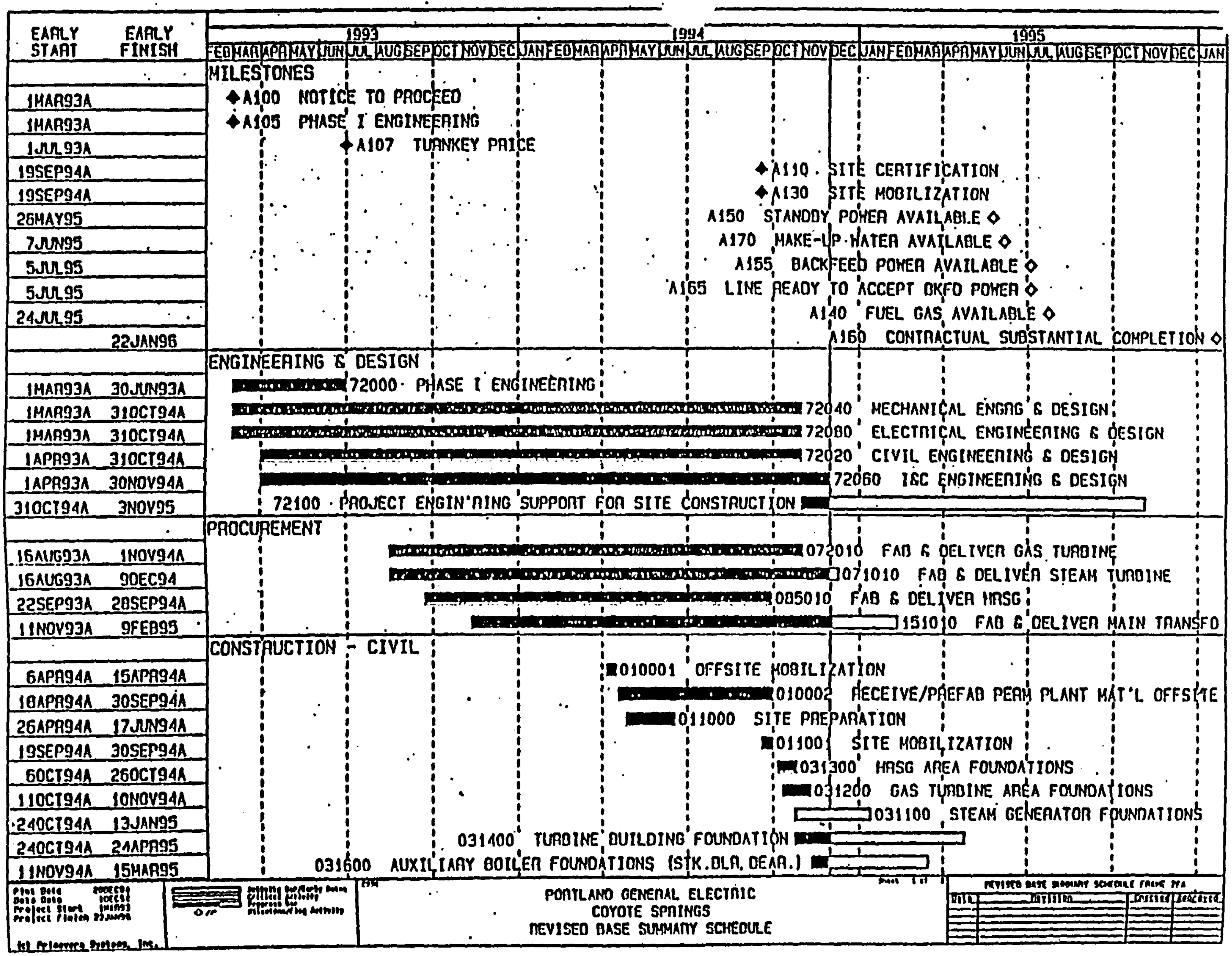
B. Notice to Proceed With Construction was not issued on or prior to March 1, 1994 as provided in Section 4 of the EPC Contract but instead was issued September 19, 1994;

C. A Stop Work Order was issued to the Contractor by the Owner on November 18, 1994 and was subsequently lifted on November 23, 1994;

D. Contractor has advised Owner that the delays in issuance of the Notice to Proceed With Construction and the delays resulting from issuance of the Stop Work Order referred to in Recital C, above, will affect the Substantial Completion Deadline and the parties have, therefore, as complete, final and binding resolution, compromise, waiver and release of all claims of Contractor which have arisen or may hereafter arise as a result of or related to such delays, negotiated an adjustment to the Substantial Completion Deadline as set forth in Section 2, below; and

C-1

APPENDIX D
PAGE 14 OF 16



EARLY START	EARLY FINISH	
		MILESTONES
1MAR93A		A100 NOTICE TO PROCEED
1MAR93A		A105 PHASE I ENGINEERING
1JUL93A		A107 TURNKEY PRICE
19SEP94A		A110 SITE CERTIFICATION
19SEP94A		A130 SITE MOBILIZATION
26MAY95		A150 STANDBY POWER AVAILABLE ◇
7JUN95		A170 MAKE-UP WATER AVAILABLE ◇
5JUL95		A155 BACKFEED POWER AVAILABLE ◇
5JUL95		A165 LINE READY TO ACCEPT BKFD POWER ◇
24JUL95		A140 FUEL GAS AVAILABLE ◇
	22JAN96	A160 CONTRACTUAL SUBSTANTIAL COMPLETION ◇
		ENGINEERING & DESIGN
1MAR93A	30JUN93A	72000 PHASE I ENGINEERING
1MAR93A	31OCT94A	72040 MECHANICAL ENGNG & DESIGN
1MAR93A	31OCT94A	72080 ELECTRICAL ENGINEERING & DESIGN
1APR93A	31OCT94A	72020 CIVIL ENGINEERING & DESIGN
1APR93A	30NOV94A	72060 I&C ENGINEERING & DESIGN
31OCT94A	3NOV95	72100 PROJECT ENGIN'RING SUPPORT FOR SITE CONSTRUCTION
		PROCUREMENT
16AUG93A	1NOV94A	072010 FAB & DELIVER GAS TURBINE
16AUG93A	9DEC94	071010 FAB & DELIVER STEAM TURBINE
22SEP93A	28SEP94A	085010 FAB & DELIVER HRSG
11NOV93A	9FEB95	151010 FAB & DELIVER MAIN TRANSFO
		CONSTRUCTION - CIVIL
6APR94A	15APR94A	010001 OFFSITE MOBILIZATION
18APR94A	30SEP94A	010002 RECEIVE/PREFAB PERM PLANT MAT'L OFFSITE
26APR94A	17JUN94A	011000 SITE PREPARATION
19SEP94A	30SEP94A	011001 SITE MOBILIZATION
6OCT94A	26OCT94A	031300 HRSG AREA FOUNDATIONS
11OCT94A	10NOV94A	031200 GAS TURBINE AREA FOUNDATIONS
24OCT94A	13JAN95	031100 STEAM GENERATOR FOUNDATIONS
24OCT94A	24APR95	031400 TURBINE BUILDING FOUNDATION
11NOV94A	15MAR95	031600 AUXILIARY BOILER FOUNDATIONS (STK.BLR.DEAR.)

PORTLAND GENERAL ELECTRIC
COYOTE SPRINGS
REVISED BASE SUMMARY SCHEDULE

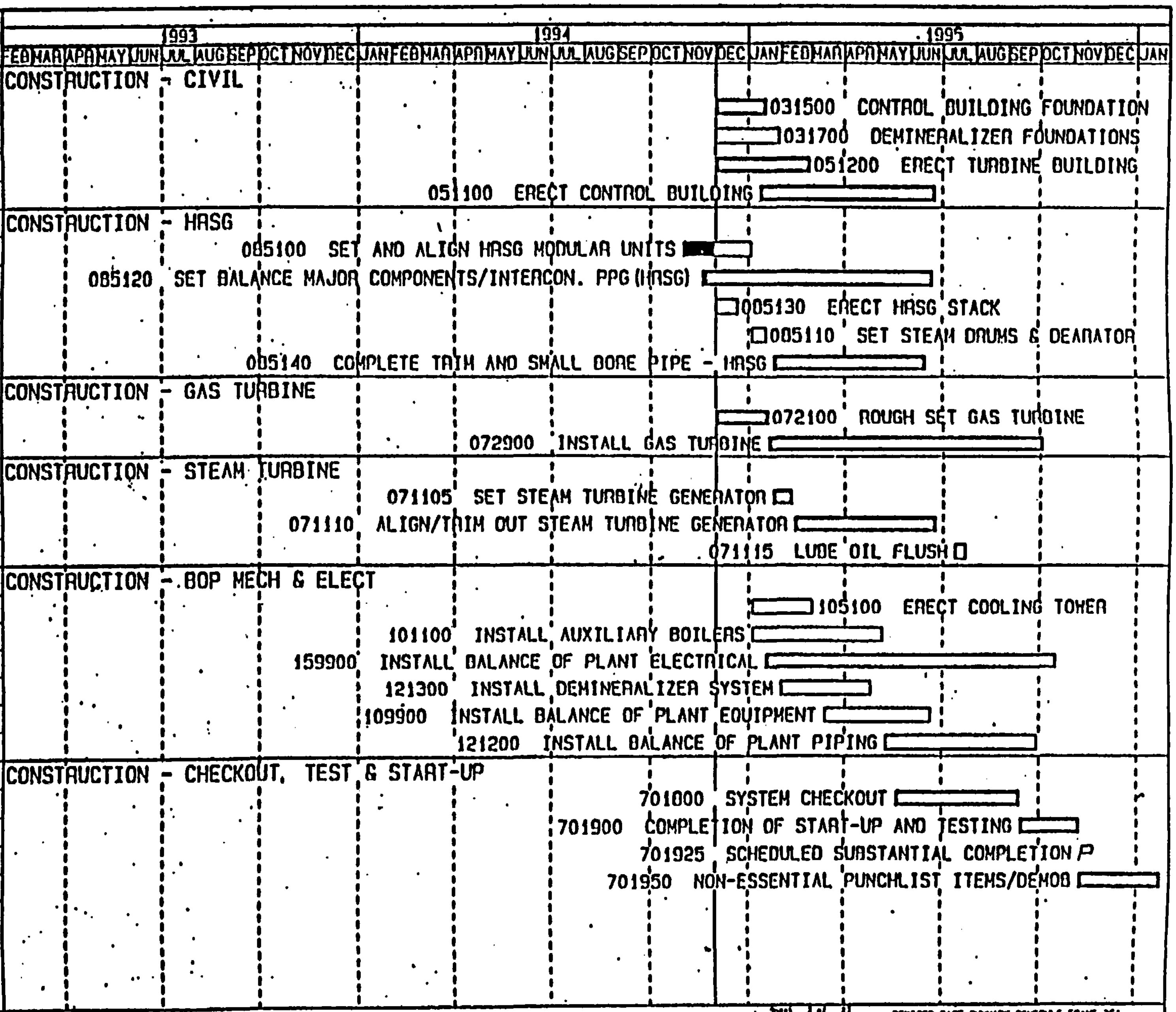
Amended Exhibit C

KEY DATES

95-322

KEY DATES

95-322



EARLY START	EARLY FINISH	
		CONSTRUCTION - CIVIL
1DEC94	17JAN95	031500 CONTROL BUILDING FOUNDATION
1DEC94	30JAN95	031700 DEMINERALIZER FOUNDATIONS
1DEC94	27FEB95	051200 ERECT TURBINE BUILDING
12JAN95	23JUN95	051100 ERECT CONTROL BUILDING
		CONSTRUCTION - HRSG
31OCT94A	3JAN95	085100 SET AND ALIGN HRSG MODULAR UNITS
18NOV94A	21JUN95	085120 SET BALANCE MAJOR COMPONENTS/INTERCON. PPG (HRSG)
1DEC94	21DEC94	005130 ERECT HRSG STACK
4JAN95	17JAN95	005110 SET STEAM DRUMS & DEARATOR
25JAN95	14JUN95	085140 COMPLETE TRIM AND SMALL BORE PIPE - HRSG
		CONSTRUCTION - GAS TURBINE
1DEC94	19JAN95	072100 ROUGH SET GAS TURBINE
20JAN95	30CT95	072900 INSTALL GAS TURBINE
		CONSTRUCTION - STEAM TURBINE
24JAN95	10FEB95	071105 SET STEAM TURBINE GENERATOR
13FEB95	23JUN95	071110 ALIGN/TRIM OUT STEAM TURBINE GENERATOR
12JUL95	21JUL95	071115 LUBE OIL FLUSH
		CONSTRUCTION - BOP MECH & ELECT
4JAN95	1MAR95	105100 ERECT COOLING TOWER
4JAN95	5MAY95	101100 INSTALL AUXILIARY BOILERS
17JAN95	16OCT95	159900 INSTALL BALANCE OF PLANT ELECTRICAL
31JAN95	24APR95	121300 INSTALL DEMINERALIZER SYSTEM
13MAR95	19JUN95	109900 INSTALL BALANCE OF PLANT EQUIPMENT
9MAY95	28SEP95	121200 INSTALL BALANCE OF PLANT PIPING
		CONSTRUCTION - CHECKOUT, TEST & START-UP
19MAY95	12SEP95	701800 SYSTEM CHECKOUT
13SEP95	7NOV95	701900 COMPLETION OF START-UP AND TESTING
	7NOV95	701925 SCHEDULED SUBSTANTIAL COMPLETION
8NOV95	22JAN96	701950 NON-ESSENTIAL PUNCHLIST ITEMS/DEMOB

Plot Date 20DEC94
Data Date 1DEC94
Project Start 1MAR93
Project Finish 22JAN96

(c) Primavera Systems, Inc.

Activity Bar/Early Dates
Critical Activity
Progress Bar
Milestone/Flag Activity

PORTLAND GENERAL ELECTRIC
COYOTE SPRINGS
REVISED BASE SUMMARY SCHEDULE

Sheet 1 of 1

REVISED BASE SUMMARY SCHEDULE FRAME 7FA

Date	Revision	Checked	Approved

(i)

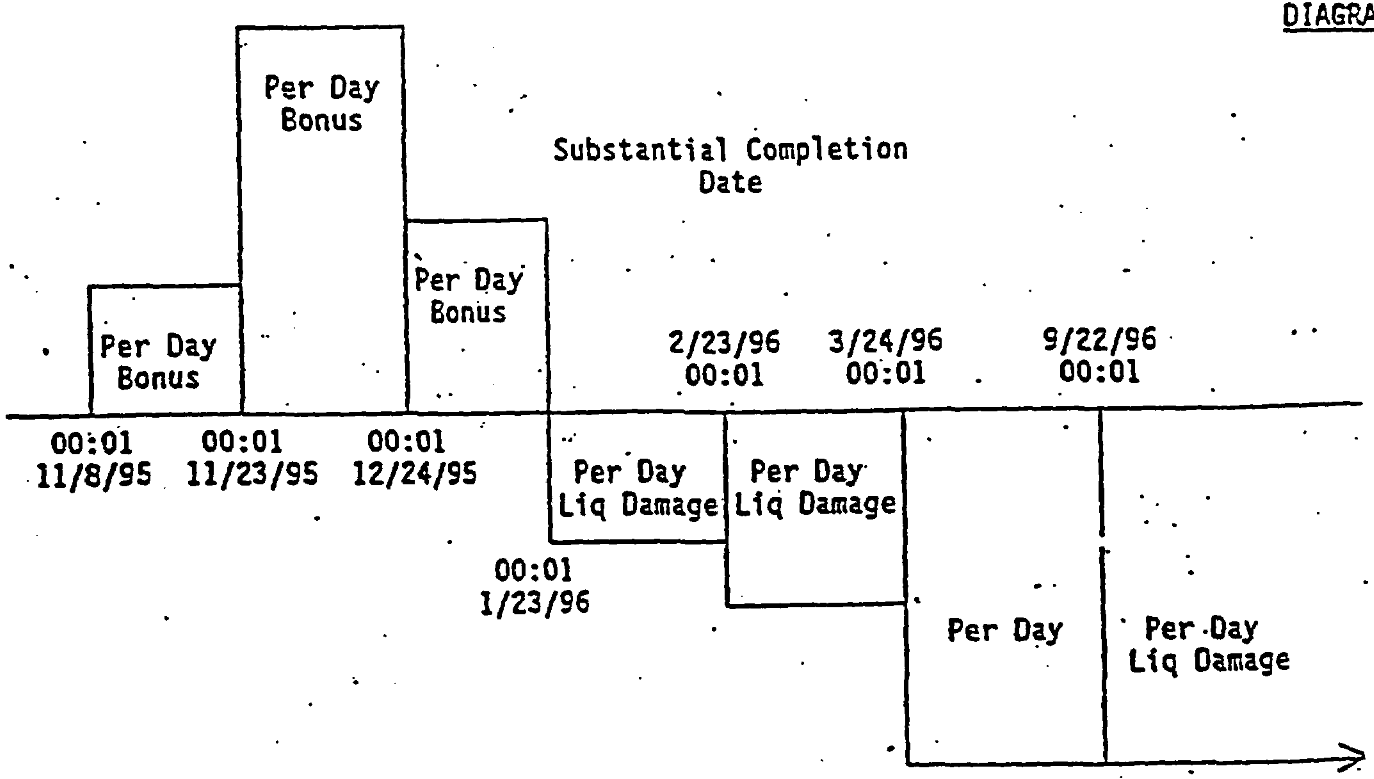
(ii)

(iii)

In no event will the Early Completion Bonus be calculated for a period of time greater than seventy-six (76) days.

The following diagram is designed to represent visually the foregoing description of the calculation of Delay Liquidated Damages and Early Completion Bonus.

DIAGRAM 3



BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 88

In the Matter of the Revised)
Tariff Schedules for Electric)
Service in Oregon Filed by) **STIPULATION**
PORTLAND GENERAL ELECTRIC)
COMPANY - Advice No. 93-26)

RECITALS

1. On November 8, 1993, Portland General Electric Company (PGE) filed for a general rate change affecting its price schedules in Advice No. 93-26. Docket UE-88 is the proceeding for resolution of the issues in Advice 93-26.

2. The new price schedules are based on PGE's expected revenue requirement for a two-year test period covering 1995 and 1996. On November 8, 1993, PGE filed testimony, exhibits, and work papers in support of its 1995 and 1996 revenue requirements.

3. On March 21, 1994, the Staff of the Public Utility Commission of Oregon (Commission) filed a motion to amend the schedule and to bifurcate UE-88. Staff requested separate consideration of issues related to PGE's Trojan Nuclear Plant that fell within the scope of the Commission's order in the DR-10 proceeding, and issues related to the cost of capital.

4. The Hearings Officers granted the motion to bifurcate on May 3, 1994 and established

a separate schedule for Phase II of UE-88, for the Trojan-related issues and cost of capital. Based on a March 25, 1994 Staff Issues List, cost of capital is identified as issue S-0 for purposes of UE-88. Equity issuance costs are identified as issue S-33. This Stipulation concerns cost of capital, in Phase II and equity issuance costs in Phase I.

5. On September 30, 1994, Staff filed its testimony, exhibits, and work papers on cost of capital, issue S-0. On November 8 and 10, 1994, conferences were noticed and held pursuant to OAR 860-14-085(3) for purposes of discussing settlement of cost of capital issues as well as equity issuance costs, issue S-33, from Phase I of UE-88.

TERMS OF STIPULATION

PGE and Staff hereby agree as follows:

6. PGE's revenue requirement will reflect the following capital structure and costs for the test years 1995 and 1996:

I. Test Year 1995

	Capital Structure	Cost%	Weighted Cost (%)
a. Long-Term Debt	49.14	7.71	3.79
b. Preferred Stock	5.42	8.27	0.45
c. Common Equity	45.44	11.60	5.27
	100.00		
Rate of Return			9.51

II. Test Year 1996

	Capital Structure%	Cost%	Weighted Cost (%)
a. Long-Term Debt	48.86	7.82	3.82
b. Preferred Stock	4.67	8.27	0.39
c. Common Equity	46.47	11.60	5.39
	100.00		
Rate of Return			9.60

7. This Stipulation for cost of capital issues is entered into notwithstanding any determination by the Commission on decoupling, issue S-38. The capital structure and costs for each year are stipulated regardless whether decoupling is implemented.

8. In resolution of issue S-33 from Phase I, PGE will increase its O&M expense and applicable income tax expense for the effect of adding $1.75 million of common equity issuance costs for both 1995 and 1996.

9. Staff and PGE will each submit separate testimony on or before November 30, 1994 supporting the provisions of this Stipulation and arguing in good faith for their adoption by the Commission.

10. This Stipulation shall be entered in the record in this proceeding as evidence pursuant to OAR 860-14-045 and 860-14-085.

11. PGE and Staff agree that all of the testimony filed in this docket on issue S-0 shall be entered into the record of UE-88. Staff and PGE further agree to waive cross-examination of the each others' testimony on items included in this Stipulation and issue S-0, and to make their respective witnesses available for cross-examination by any other party to UE-88.

12. If any issue covered by this Stipulation or related to issue S-0 is challenged by someone not a party to this Stipulation, Staff and PGE agree to support and argue in good faith for the Commission's approval of all of the provisions of this Stipulation.

13. Staff and PGE have entered into this Stipulation to resolve issue S-0, related to the cost of capital. They shall not be deemed to have agreed that this Stipulation is appropriate for resolving issues in any other proceeding. Further, they shall not be deemed to have accepted or consented to the principles, methods, or theories employed in arriving at this Stipulation.

14. If the Commission rejects any portion of this Stipulation, Staff or PGE may withdraw from the Stipulation in its entirety.

Signed this 15th day of November, 1994.

Kimberly R Cobrain
Kim Cobrain
of Attorneys for the Staff of the
Oregon Public Utility Commission

Rochelle Lessner
of Attorneys for Portland General
Electric Company

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PORTLAND GENERAL ELECTRIC CO.
Adjustment Summary
UE 88 - 1995 & 1996 Test Years

($ x 1,000)

Item	Issue	Revenue Requirement Effect	
		1995	1996
	Company-calculated added revenues required	$46,498	$109,267
	STIPULATED ADJUSTMENTS		
S-0,S-35	Rate of Return and Capital Structure	(61)	(3,124)
S-1	PGC Inflation	(315)	(662)
S-2	EPRI Deferral	0	0
S-3	Advertising - Category "C"	(24)	(25)
S-4	Retirement Savings Plan	(1,267)	(1,532)
S-5	Legal Escalation	(1,541)	(165)
S-6	Health Insurance Escalation	(323)	(723)
S-7	Overhead Billing	(778)	(777)
S-8	Service Provider Costs	1,926	3,041
S-9	WTC Improvements	59	57
S-10	Managers' Deferred Compensation	713	832
S-11	Income Tax Adjustments	(89)	(467)
S-12	Load Forecast	(1,622)	(26)
S-13	Variable Power Costs	(13,853)	(61,334)
S-14	Miscellaneous Electric Revenues	(1,504)	(1,539)
S-16	Incentive Pay Adjustment	(4,280)	(4,413)
S-17	Supplemental Executive Retirement	(1,852)	(1,780)
S-18	Managers' Deferred Compensation	(1,835)	(2,162)
S-19	Directors' Deferred Compensation and Pensions	(210)	(200)
S-20	Medical Insurance	(332)	(808)
S-21	EPRI Membership Replacement	0	0
S-22	Escalation Rate Update	(1,105)	(1,641)
S-23	Non-Labor Customer Accounts	(106)	(111)
S-24	Community Development	(302)	(311)
S-25	Market Intelligence	(224)	(235)
S-26	CS2 Project	(93)	(4,428)
S-27	Advertising - Category "A"	(109)	(384)
S-28	Power Smart	(116)	(120)
S-30	Energy Resource Center	(217)	(217)
S-31	Energy Efficiency	5,001	13,473
S-33	Equity Issuance Costs	0	(3,571)
S-34	Payroll Tax Rate	(20)	(401)
S-35	Revised Interest from ROR Change (RR included in S-O)	0	0
S-36	Non-Fuel Material and Supplies	(75)	(149)
S-37	Remove Boardman Gain Acceleration	36,313	31,309
	Total Stipulated Adjustments	11,759	(42,593)
	UNSTIPULATED ADJUSTMENTS		
S-15	Wage and Salary Adjustment	(446)	(834)
S-29	HVEA Promotions	(1,292)	(1,555)
S-32	PGC Allocation	(202)	(216)
S-45	Trojan Overtime	(427)	(382)
S-46	Trojan Plant Reclassification	0	0
S-47	Trojan Salvage Recovery	(843)	(818)
S-48	Decommissioning Trust Accrual Reduction	(664)	(789)
S-49	Remove Plugging, Sleeving, Analysis and Reactor Pump	(3,945)	(3,808)
S-50	Remove Additional Trojan Fixed Costs to Reach 86.9 Percent	(5,798)	(5,491)
S-51	Remove Trojan Power Cost Deferral	3,305	3,337
S-52	Update Trojan Plant Income Tax Write-Off	871	1,119
S-53	Trojan Intangible Asset	0	0
	One Percent Discretionary Costs Reduction	(1,631)	(1,687)
	Total Unstipulated Adjustments	(11,072)	(11,124)
	Total Adjustments	687	(53,717)
	Revenue Requirements Change	$47,185	$55,550

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PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1995
(000)

		1995 Per Company Filing (1)	Adjustments (2)	1995 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Operating Revenues					
2	Sales to Consumers	$885,257	$846	$886,103	$47,185	$933,288
3	Other Revenues	8,385	2,410	10,795	0	10,795
4	**Total Operating Revenues**	$893,642	$3,256	$896,898	$47,185	$944,083
5	Operating Expenses and Taxes					
6	Operation & Maintenance					
7	Net Variable Power Costs	$320,346	($13,547)	$306,799	$0	$306,799
8	Fixed Power Costs	71,532	0	71,532	0	71,532
9	Other Oper.& Maint.	147,951	(13,311)	134,640	203	134,843
10	**Total Operation & Maintenance**	$539,829	($26,858)	$512,971	$203	$513,174
11	Depreciation & Amortization	115,170	31,712	146,882	0	146,882
12	Taxes Other than Income	49,471	(892)	48,579	991	49,570
13	Income Taxes	62,438	(481)	61,957	18,139	80,096
14						
15	**Total Operating Expenses and Taxes**	$766,908	$3,481	$770,389	$19,333	$789,722
16	**Utility Operating Income**	$126,734	($225)	$126,509	$27,848	$154,357
17	Average Rate Base					
18	Utility Plant In Service	$2,651,345	($155,912)	$2,495,433	$0	$2,495,433
19	Accumulated Depreciation	(1,099,656)	72,395	(1,027,261)	0	(1,027,261)
20	Accumulated Deferred Income Taxes	(235,810)	134,771	(101,039)	0	(101,039)
21	Accumulated Deferred Inv. Tax Credit	(54,317)	8,912	(45,405)	0	(45,405)
22	**Net Utility Plant**	$1,261,562	$60,166	$1,321,728	$0	$1,321,728
23	Energy Efficiency	66,801	19,916	86,717	0	86,717
24	Boardman Gain	(99,463)	(18,354)	(117,817)	0	(117,817)
25	Deferred Trojan Investment	291,467	(51,330)	240,137	0	240,137
26	Materials & Supplies - Fuel	14,811	0	14,811	0	14,811
27	- Other	25,973	(5,164)	20,809	0	20,809
28	Working Cash	36,634	92	36,726	880	37,606
29	Misc. Deferred Debits	33,273	0	33,273	0	33,273
30	Misc. Deferred Credits	(15,501)	1,677	(13,824)	0	(13,824)
31	**Total Average Rate Base**	$1,615,557	$7,003	$1,622,560	$880	$1,623,440
32	**Rate of Return**	7.84%		7.80%		9.51%
33	**Implied Return on Equity**	7.67%		7.83%		11.60%

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Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Miscellaneous Corrections to Company Filing					
		PGC Inflation (S-1)	EPRI Deferral (S-2)	Category 'C' Advertising (S-3)	Retirement Savings Plan (S-4)	Legal Escalation (S-5)	Health Insurance Escalation (S-6)
1	Operating Revenues						
2	Sales to Consumers	$0	$0	$0	$0	$0	$0
3	Other Revenues		0				
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes						
6	Operation & Maintenance						
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs						
9	Other Oper.& Maint.	(299)	0	(23)	(1,230)	(1,497)	(314)
10	**Total Operation & Maintenance**	($299)	$0	($23)	($1,230)	($1,497)	($314)
11	Depreciation & Amortization	0	0	0	0	0	0
12	Taxes Other than Income	(7)	0	0	0	0	0
13	Income Taxes	121	(0)	9	486	591	124
14							
15	**Total Operating Expenses and Taxes**	($185)	($0)	($14)	($744)	($906)	($190)
16	**Utility Operating Income**	$185	$0	$14	$744	$906	$190
17	Average Rate Base						
18	Utility Plant in Service	$0	$0	$0	$0	$0	$0
19	Accumulated Depreciation	0	0	0	0	0	0
20	Accumulated Deferred Income Taxes	0	0	0	0	0	0
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	$0
23	Energy Efficiency						
24	Boardman Gain	0	0	0	0	0	0
25	Trojan Investment						
26	Materials & Supplies - Fuel						
27	- Other						
28	Working Cash	(8)	(0)	(1)	(34)	(41)	(9)
29	Misc. Deferred Debits						
30	Misc. Deferred Credits						
31	**Total Average Rate Base**	($8)	($0)	($1)	($34)	($41)	($9)
32	**Revenue Requirement Effect**	($315)	$0	($24)	($1,267)	($1,541)	($323)

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Miscellaneous Corrections to Company Filing						
		Overhead Billing (S-7)	Service Provider Costs (S-8)	WTC Improvements (S-9)	Managers Def. Comp. (S-10)	Income Tax Adjustments (S-11)	Load Forecast (S-12)	Variable Power Costs (S-13)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$4,932	$0
3	Other Revenues	687						
4	**Total Operating Revenues**	$687	$0	$0	$0	$0	$4,932	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$2,554	($13,445)
8	Fixed Power Costs							
9	Other Oper.& Maint.	(73)	1,870	0	692	0	281	0
10	**Total Operation & Maintenance**	($73)	$1,870	$0	$692	$0	$2,835	($13,445)
11	Depreciation & Amortization	0					85	
12	Taxes Other than Income	0	0	0	0	0	137	0
13	Income Taxes	300	(738)	(7)	(273)	(192)	707	5,310
14								
15	**Total Operating Expenses and Taxes**	$227	$1,132	($7)	$419	($192)	$3,763	($8,135)
16	**Utility Operating Income**	$460	($1,132)	$7	($419)	$192	$1,169	$8,135
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$690	$0	$0	$2,135	$0
19	Accumulated Depreciation	0		(252)			(85)	
20	Accumulated Deferred Income Taxes	0				1,478	0	
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$438	$0	$1,478	$2,050	$0
23	Energy Efficiency	0	0	0	0	0		0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other			0		0		0
28	Working Cash	10	51	(0)	19	(9)	171	(437)
29	Misc. Deferred Debits	0						
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	$10	$51	$438	$19	$1,469	$2,221	($437)
32	**Revenue Requirement Effect**	($778)	$1,926	$59	$713	($89)	($1,622)	($13,853)

APPENDIX F
PAGE 4 OF 35

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Miscellaneous Electric Revenues (S-14)	Wage & Salary Adjustment (S-15)	Incentive Pay Adjustment (S-16)	Supplemental Executive Retirement (S-17)	Managers' Deferred Compensation (S-18)	Directors' Deferred Comp. & Pensions (S-19)	Medical Insurance (S-20)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues	1,469						
4	**Total Operating Revenues**	$1,469	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	(383)	(3,745)	(1,957)	(1,845)	(204)	(314)
10	**Total Operation & Maintenance**	$0	($383)	($3,745)	($1,957)	($1,845)	($204)	($314)
11	Depreciation & Amortization	0	0		0			0
12	Taxes Other than Income	0	(42)	(412)	0	0	0	0
13	Income Taxes	579	169	1,642	755	721	81	125
14								
15	**Total Operating Expenses and Taxes**	$579	($256)	($2,515)	($1,202)	($1,124)	($123)	($189)
16	**Utility Operating Income**	$890	$256	$2,515	$1,202	$1,124	$123	$189
17	Average Rate Base							
18	Utility Plant in Service	$0	($61)	$0	$0	$0	$0	($65)
19	Accumulated Depreciation	0	0		0			0
20	Accumulated Deferred Income Taxes	0	0		0			0
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	($61)	$0	$0	$0	$0	($65)
23	Energy Efficiency			0		0	0	
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other			0		0	0	
28	Working Cash	26	(12)	(114)	(55)	(51)	(6)	(9)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits				1,200	477	0	
31	**Total Average Rate Base**	$26	($73)	($114)	$1,145	$426	($6)	($74)
32	**Revenue Requirement Effect**	($1,504)	($446)	($4,280)	($1,852)	($1,835)	($210)	($332)

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		EPRI Membership Replacement (S-21)	Escalation Rate Update (S-22)	Non-Labor Cust. Accts. (S-23)	Community Development (S-24)	Market Intelligence (S-25)	CS2 Project (S-26)	Advertising Category "A" (S-27)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues							
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	(1,073)	(103)	(278)	(203)	0	(106)
10	**Total Operation & Maintenance**	$0	($1,073)	($103)	($278)	($203)	$0	($106)
11	Depreciation & Amortization			0				
12	Taxes Other than Income	0	0	0	(15)	(15)	0	0
13	Income Taxes	(0)	424	41	116	86	10	42
14								
15	**Total Operating Expenses and Taxes**	($0)	($649)	($62)	($177)	($132)	$10	($64)
16	**Utility Operating Income**	$0	$649	$62	$177	$132	($10)	$64
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	$0	($687)	$0
19	Accumulated Depreciation			0				
20	Accumulated Deferred Income Taxes			0				
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	($687)	$0
23	Energy Efficiency	0	0	0	0	0	0	0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other	0	0					
28	Working Cash	(0)	(30)	(3)	(8)	(6)	0	(3)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	($0)	($30)	($3)	($8)	($6)	($687)	($3)
32	**Revenue Requirement Effect**	$0	($1,105)	($106)	($302)	($224)	($93)	($109)

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Power Smart (S-28)	HVEA Promotions (S-29)	Energy Resource Center (ERC) (S-30)	Energy Efficiency (S-31)	PGC Allocation (S-32)	Equity Issuance Costs (S-33)	Payroll Tax Rate (S-34)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	($4,086)	$0	$0	$0
3	Other Revenues			0	254			
4	**Total Operating Revenues**	$0	$0	$0	($3,832)	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	($2,656)	$0	$0	$0
8	Fixed Power Costs		0	0			0	
9	Other Oper.& Maint.	(108)	(1,203)	(211)	1,165	(196)	0	0
10	**Total Operation & Maintenance**	($108)	($1,203)	($211)	($1,491)	($196)	$0	$0
11	Depreciation & Amortization						0	
12	Taxes Other than Income	(5)	(52)	0	(86)	0	0	(19)
13	Income Taxes	45	496	83	(1,186)	77	(0)	8
14								
15	**Total Operating Expenses and Taxes**	($68)	($759)	($128)	($2,762)	($119)	($0)	($11)
16	**Utility Operating Income**	$68	$759	$128	($1,070)	$119	$0	$11
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	$0	$0	($4)
19	Accumulated Depreciation							
20	Accumulated Deferred Income Taxes				0			
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	$0	($4)
23	Energy Efficiency	0	0	0	19,916	0	0	0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment			0				
26	Materials & Supplies - Fuel							
27	- Other					0		
28	Working Cash	(3)	(35)	(6)	(126)	(5)	(0)	(1)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	($3)	($35)	($6)	$19,790	($5)	($0)	($5)
32	**Revenue Requirement Effect**	($116)	($1,292)	($217)	$5,001	($202)	$0	($20)

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Revised Interest from ROR Change (S-35)	Non-Fuel Materials & Supplies (S-36)	Remove Boardman Gain Accel. (S-37)	Trojan Overtime (S-45)	Trojan Plant Reclassification (S-46)	Trojan Salvage Recovery (S-47)	Decommissioning Trust Accrual Reduction (S-48)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues							
4	**Total Operating Revenues**	$0	$0	$0	$0	$0.	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	0	0	(365)	0	0	0
10	**Total Operation & Maintenance**	$0	$0	$0	($365)	$0	$0	$0
11	Depreciation & Amortization			36,707	0	0	(353)	(1,072)
12	Taxes Other than Income	0	0	0	(40)	0	0	0
13	Income Taxes	448	8	(14,315)	161	0	192	375
14								
15	**Total Operating Expenses and Taxes**	$448	$8	$22,392	($244)	$0	($161)	($697)
16	**Utility Operating Income**	($448)	($8)	($22,392)	$244	$0	$161	$697
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	($71)	($155,559)	$0	$0
19	Accumulated Depreciation			0	0	72,732	0	0
20	Accumulated Deferred Income Taxes			7,233	0	102,367	0	(664)
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	8,912	0	0
22	**Net Utility Plant**	$0	$0	$7,233	($71)	$28,452	$0	($664)
23	Energy Efficiency	0	0					
24	Boardman Gain	0	0	(18,354)	0	0	0	0
25	Trojan Investment					(23,841)	(3,529)	3,908
26	Materials & Supplies - Fuel							
27	- Other		(553)			(4,611)		
28	Working Cash	20	0	1,019	(11)	0	(7)	(32)
29	Misc. Deferred Debits			0	0	0	0	0
30	Misc. Deferred Credits			0	0	0	0	0
31	**Total Average Rate Base**	$20	($553)	($10,102)	($82)	$0	($3,536)	$3,212
32	**Revenue Requirement Effect**	$762	($75)	$36,313	($427)	$0	($843)	($664)

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Remove Plugging, Sleeving, Analysis & Reactor Pump (S-49)	Remove Additional Trojan Fixed Costs to Reach 86.9% (S-50)	Remove Trojan Power Cost Deferral (S-51)	Update Trojan Plant Income Tax Write-off (S-52)	Trojan Intangible Asset (S-53)	Reduce Discretionary Costs by 1%	Total Adjustments
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$846
3	Other Revenues							2,410
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$3,256
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	($13,547)
8	Fixed Power Costs							0
9	Other Oper.& Maint.	0	(6)	0	0	0	(1,584)	(13,311)
10	**Total Operation & Maintenance**	$0	($6)	$0	$0	$0	($1,584)	(26,858)
11	Depreciation & Amortization	(1,652)	(2,003)	0	0	0	0	31,712
12	Taxes Other than Income	0	(336)	0	0	0	0	(892)
13	Income Taxes	906	820	(364)	(87)	0	626	(481)
14								
15	**Total Operating Expenses and Taxes**	($746)	($1,525)	($364)	($87)	$0	($958)	$3,481
16	**Utility Operating Income**	$746	$1,525	$364	$87	$0	$958	($225)
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	($2,290)	$0	($155,912)
19	Accumulated Depreciation	0	0	0	0	0	0	72,395
20	Accumulated Deferred Income Taxes	0	0	24,357	0	0	0	134,771
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	8,912
22	**Net Utility Plant**	$0	$0	$24,357	$0	($2,290)	$0	$60,166
23	Energy Efficiency							19,916
24	Boardman Gain	0	0	0	0	0	0	(18,354)
25	Trojan Investment	(16,606)	(19,878)		6,326	2,290	0	(51,330)
26	Materials & Supplies - Fuel							0
27	- Other							(5,164)
28	Working Cash	(34)	(69)	(17)	(4)	0	(44)	92
29	Misc. Deferred Debits	0	0	0	0	0	0	0
30	Misc. Deferred Credits	0	0	0	0	0	0	1,677
31	**Total Average Rate Base**	($16,640)	($19,947)	$24,340	$6,322	$0	($44)	$7,003
32	**Revenue Requirement Effect**	($3,945)	($5,798)	$3,305	$871	$0	($1,631)	$1,508

95-322

23-Mar-95
05:28 PM

PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1995
(000)

Income Tax Calculations	1995 Per Company Filing (1)	Adjustments (2)	1995 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
Book Revenues	$893,642	$3,256	$896,898	$47,185	$944,083
Book Expenses Other than Depreciation	589,300	(27,751)	561,549	1,194	562,743
State Tax Depreciation	115,170	(4,642)	110,528		110,528
Interest	62,350	(871)	61,479	33	61,512
Book-Tax (Schedule M) Differences	(17,306)	(10,913)	(28,219)		(28,219)
State Taxable Income	$144,128	$47,433	$191,561	$45,958	$237,518
State Income Tax @ 6.672%	$9,634	$3,165	$12,799	$3,066	$15,865
	166	0	166		166
Net State Income Tax	**$9,468**	**$3,165**	**$12,633**	**$3,066**	**$15,699**
Additional Tax Depreciation	0	0	0		0
Other Schedule M Differences	0	0	0		0
Federal Taxable Income	$135,168	$43,760	$178,928	$42,892	$221,820
Federal Tax @ 35%	$47,309	$15,316	$62,625	$15,022	$77,647
ITC	0	0	0	0	0
Current Federal Tax	**$47,309**	**$15,316**	**$62,625**	**$15,022**	**$77,647**
Environmental Tax @ 0.12%	**$152**	**$53**	**$205**	**51**	**$256**
ITC Adjustment					
Deferral	$0	$0	$0	$0	$0
Restoration	2,039	(54)	1,985		1,985
Total ITC Adjustment	**($2,039)**	**$54**	**($1,985)**	**$0**	**($1,985)**
Provision for Deferred Taxes	**$7,548**	**($19,068)**	**($11,520)**	**$0**	**($11,520)**
Total Income Tax	**$62,438**	**($481)**	**$61,957**	**$18,139**	**$80,096**

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Miscellaneous Corrections to Company Filing					
	Income Tax Calculations	PGC Inflation (S-1)	EPRI Deferral (S-2)	Category 'C' Advertising (S-3)	Retirement Savings Plan (S-4)	Legal Escalation (S-5)	Health Insurance Escalation (S-6)
33	Book Revenues	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	(306)	0	(23)	(1,230)	(1,497)	(314)
35	State Tax Depreciation	0	0	0	0	0	0
36	Interest	(0)	(0)	(0)	(1)	(2)	(0)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0
38	State Taxable Income	$306	$0	$23	$1,231	$1,499	$314
39	State Income Tax @ 6.672%	$20	$0	$2	$82	$100	$21
40	State Tax Credit						
41	**Net State Income Tax**	$20	$0	$2	$82	$100	$21
42	Additional Tax Depreciation	0	0	0	0	0	0
43	Other Schedule M Differences						
44	Federal Taxable Income	$286	$0	$21	$1,149	$1,399	$293
45	Federal Tax @ 35%	$100	$0	$8	$402	$490	$103
46	ITC	0	0	0	0	0	0
47	**Current Federal Tax**	$100	$0	$8	$402	$490	$103
48	**Environmental Tax @ 0.12%**	$0	$0	$0	$1	$2	$0
49	ITC Adjustment						
50	Deferral	$0	$0	$0	$0	$0	$0
51	Restoration						
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$0
54	**Total Income Tax**	$121	$0	$9	$486	$591	$124

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Miscellaneous Corrections to Company Filing						
		Overhead Billing (S-7)	Service Provider Costs (S-8)	WTC Improvements (S-9)	Managers Def. Comp. (S-10)	Income Tax Adjustments (S-11)	Load Forecast (S-12)	Variable Power Costs (S-13)
33	Book Revenues	$687	$0	$0	$0	$0	$4,932	$0
34	Book Expenses Other than Depreciation	(73)	1,870	0	692	0	2,972	(13,445)
35	State Tax Depreciation	0	0	0	0	0	85	0
36	Interest	0	2	17	1	56	84	(17)
37	Book-Tax (Schedule M) Differences	0	0	0	0	(7,512)	0	0
38	State Taxable Income	$760	($1,872)	($17)	($693)	$7,456	$1,791	$13,462
39	State Income Tax @ 6.672%	$51	($125)	($1)	($46)	$497	$119	$898
40	State Tax Credit							
41	**Net State Income Tax**	**$51**	**($125)**	**($1)**	**($46)**	**$497**	**$119**	**$898**
42	Additional Tax Depreciation	0	0	0	0		0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$709	($1,747)	($15)	($647)	$6,451	$1,672	$12,563
45	Federal Tax @ 35%	$248	($611)	($5)	($226)	$2,258	$585	$4,397
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	**$248**	**($611)**	**($5)**	**($226)**	**$2,258**	**$585**	**$4,397**
48	**Environmental Tax @ 0.12%**	**$1**	**($2)**	**($0)**	**($1)**	**$8**	**$2**	**$15**
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
53	**Provision for Deferred Taxes**	**$0**	**$0**	**$0**	**$0**	**($2,955)**	**$0**	**$0**
54	**Total Income Tax**	**$300**	**($738)**	**($7)**	**($273)**	**($192)**	**$707**	**$5,310**

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Miscellaneous Electric Revenues (S-14)	Wage & Salary Adjustment (S-15)	Incentive Pay Adjustment (S-16)	Supplemental Executive Retirement (S-17)	Managers' Deferred Compensation (S-18)	Directors' Deferred Comp. & Pensions (S-19)	Medical Insurance (S-20)
33	Book Revenues	$1,469	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	(425)	(4,157)	(1,957)	(1,845)	(204)	(314)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	1	(3)	(4)	43	16	(0)	(3)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$1,468	$428	$4,161	$1,914	$1,829	$204	$317
39	State Income Tax @ 6.672%	$98	$29	$278	$128	$122	$14	$21
40	State Tax Credit							
41	**Net State Income Tax**	$98	$29	$278	$128	$122	$14	$21
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$1,370	$399	$3,884	$1,786	$1,707	$191	$296
45	Federal Tax @ 35%	$480	$140	$1,359	$625	$597	$67	$103
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$480	$140	$1,359	$625	$597	$67	$103
48	**Environmental Tax @ 0.12%**	$2	$0	$5	$2	$2	$0	$0
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$0	$0
54	**Total Income Tax**	$579	$169	$1,642	$755	$721	$81	$125

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	EPRI Membership Replacement (S-21)	Escalation Rate Update (S-22)	Non-Labor Cust. Accts, (S-23)	Community Development (S-24)	Market Intelligence (S-25)	CS2 Project (S-26)	Advertising Category "A" (S-27)
33	Book Revenues	$0	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	(1,073)	(103)	(293)	(218)	0	(106)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	(0)	(1)	(0)	(0)	(0)	(26)	(0)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	*State Taxable Income*	$0	$1,074	$103	$293	$218	$26	$106
39	State Income Tax @ 6.672%	$0	$72	$7	$20	$15	$2	$7
40	State Tax Credit							
41	**Net State Income Tax**	$0	$72	$7	$20	$15	$2	$7
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$0	$1,002	$96	$274	$204	$24	$99
45	Federal Tax @ 35%	$0	$351	$34	$96	$71	$8	$35
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$0	$351	$34	$96	$71	$8	$35
48	**Environmental Tax @ 0.12%**	$0	$1	$0	$0	$0	$0	$0
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$0	$0
54	**Total Income Tax**	$0	$424	$41	$116	$86	$10	$42

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Power Smart (S-28)	HVEA Promotions (S-29)	Energy Resource Center (ERC) (S-30)	Energy Efficiency (S-31)	PGC Alloc/Inflation (S-32)	Equity Issuance Costs (S-33)	Payroll Tax Rate (S-34)
33	Book Revenues	$0	$0	$0	($3,832)	$0	$0	$0
34	Book Expenses Other than Depreciation	(113)	(1,255)	(211)	(1,576)	(196)	0	(19)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	(0)	(1)	(0)	750	(0)	(0)	(0)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$113	$1,256	$211	($3,005)	$196	$0	$19
39	State Income Tax @ 6.672%	$8	$84	$14	($201)	$13	$0	$1
40	State Tax Credit							
41	**Net State Income Tax**	$8	$84	$14	($201)	$13	$0	$1
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$106	$1,172	$197	($2,805)	$183	$0	$18
45	Federal Tax @ 35%	$37	$410	$69	($982)	$64	$0	$6
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$37	$410	$69	($982)	$64	$0	$6
48	**Environmental Tax @ 0.12%**	$0	$1	$0	($3)	$0	$0	$0
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$0	$0
54	**Total Income Tax**	$45	$496	$83	($1,186)	$77	$0	$8

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Revised Interest from ROR Change (S-35)	Non-Fuel Materials & Supplies (S-36)	Remove Boardman Gain Accel. (S-37)	Trojan Overtime (S-45)	Trojan Plant Reclassification (S-46)	Trojan Salvage Recovery (S-47)	Decommissioning Trust Accrual Reduction (S-48)
33	Book Revenues	$0	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	0	0	(405)	0	0	0
35	State Tax Depreciation	0	0	0	0	0	0	(1,072)
36	Interest	(1,136)	(21)	(383)	(3)	0	(134)	122
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	(3,381)
38	State Taxable Income	$1,136	$21	$383	$408	$0	$134	$4,331
39	State Income Tax @ 6.672%	$76	$1	$26	$27	$0	$9	$289
40	State Tax Credit							
41	**Net State Income Tax**	**$76**	**$1**	**$26**	**$27**	**$0**	**$9**	**$289**
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences	0		0	0	0	0	0
44	Federal Taxable Income	$1,060	$20	$357	$381	$0	$125	$4,042
45	Federal Tax @ 35%	$371	$7	$125	$133	$0	$44	$1,415
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	**$371**	**$7**	**$125**	**$133**	**$0**	**$44**	**$1,415**
48	**Environmental Tax @ 0.12%**	**$1**	**$0**	**$0**	**$0**	**$0**	**$0**	**$5**
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
53	**Provision for Deferred Taxes**	**$0**	**$0**	**($14,466)**	**$0**	**$0**	**$139**	**($1,334)**
54	**Total Income Tax**	**$448**	**$8**	**($14,315)**	**$161**	**$0**	**$192**	**$375**

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Remove Plugging, Sleeving, Analysis & Reactor Pump (S-49)	Remove Additional Trojan Fixed Costs to Reach 86.9% (S-50)	Remove Trojan Power Cost Deferral (S-51)	Update Trojan Plant Income Tax Write-off (S-52)	Trojan Intangible Asset (S-53)	Reduce Discretionary Costs by 1%	Total Adjustments
33	Book Revenues	$0	$0	$0	$0	$0	$0	$3,256
34	Book Expenses Other than Depreciation	0	(342)	0	0	0	(1,584)	($27,751)
35	State Tax Depreciation	0	(3,655)	0	0	0	0	($4,642)
36	Interest	(630)	(756)	922	240	0	(2)	($871)
37	Book-Tax (Schedule M) Differences	0	4,440	0	(4,460)	0	0	($10,913)
38	State Taxable Income	$630	$313	($922)	$4,220	$0	$1,586	$47,433
39	State Income Tax @ 6.672%	$42	$21	($62)	$282	$0	$106	$3,165
40	State Tax Credit							$0
41	**Net State Income Tax**	$42	$21	($62)	$282	$0	$106	$3,165
42	Additional Tax Depreciation	0	0	0	0	0	0	$0
43	Other Schedule M Differences	0	0	0	0	0	0	$0
44	Federal Taxable Income	$588	$292	($861)	$3,939	$0	$1,480	$43,760
45	Federal Tax @ 35%	$206	$102	($301)	$1,379	$0	$518	$15,316
46	ITC	0	0	0	0	0	0	$0
47	**Current Federal Tax**	$206	$102	($301)	$1,379	$0	$518	$15,316
48	**Environmental Tax @ 0.12%**	$1	$0	($1)	$5	$0	$2	$53
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration		(54)					($54)
52	**Total ITC Adjustment**	$0	$54	$0	$0	$0	$0	$54
53	**Provision for Deferred Taxes**	$657	$643	$0	($1,752)	$0	$0	($19,068)
54	**Total Income Tax**	$906	$820	($364)	($87)	$0	$626	($461)

95-322

PORTLAND GENERAL ELECTRIC CO.
General Rate Case Settlement - UE 88
(000)

COST OF CAPITAL - 1995

	AMOUNTS	% OF CAPITAL	COST	COST
Long Term Debt	$964,369	49.14%	7.71%	3.79%
Preferred Stock	106,370	5.42%	8.27%	0.45%
Common Equity	891,644	45.44%	11.60%	5.27%
Total	$1,962,383	100.00%		9.51%

REVENUE SENSITIVE COSTS

Revenues	1.00000
O&M - Uncollectibles/OPUC Fee*	0.00430
Other Taxes-Franchise	0.02100
Short-Term Interest	0.00000
Other Taxes	0.00000
State Taxable Income	0.97470
State Income Tax @ 6.672%**	0.06503
Federal Taxable Income	0.90967
Federal Income Tax @ 35%	0.31838
ITC	0.00000
Current FIT	0.31838
ITC Adjustment/Env. Tax	0.00109
Total Income Taxes	0.38451
Total Revenue Sensitive Costs	0.40981
Utility Operating Income	0.59019
Net-to-Gross Factor	1.69436

* Uncollectible Rate	0.00230
OPUC Fee	0.00200
Total	0.00430

** State Income Tax	
Montana (.0675*.050008)	0.00338
Oregon (.0660*.959764)	0.06334
Total	0.06672

95-322

23-Mar-95
05:45 PM

PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1996
(000)

		1996 Per Company Filing (1)	Adjustments (2)	1996 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Operating Revenues					
2	Sales to Consumers	$910,200	($10,372)	$899,828	$55,550	$955,378
3	Other Revenues	8,719	2,436	11,155	0	11,155
4	**Total Operating Revenues**	$918,919	($7,936)	$910,983	$55,550	$966,533
5	Operating Expenses and Taxes					
6	Operation & Maintenance					
7	Net Variable Power Costs	$378,238	($66,424)	$311,814	$0	$311,814
8	Fixed Power Costs	73,745	0	73,745	0	73,745
9	Other Oper.& Maint.	152,949	(12,865)	140,084	239	140,323
10	**Total Operation & Maintenance**	$604,932	($79,289)	$525,643	$239	$525,882
11	Depreciation & Amortization	124,955	26,846	151,801	0	151,801
12	Taxes Other than Income	49,092	(1,467)	47,625	1,167	48,792
13	Income Taxes	43,748	15,821	59,569	21,354	80,923
14						
15	**Total Operating Expenses and Taxes**	$822,727	($38,089)	$784,638	$22,760	$807,398
16	**Utility Operating Income**	$96,192	$30,153	$126,345	$32,785	$159,130
17	Average Rate Base					
18	Utility Plant in Service	$2,778,739	($162,981)	$2,615,759	$0	$2,615,759
19	Accumulated Depreciation	(1,200,062)	78,752	(1,121,310)	0	(1,121,310)
20	Accumulated Deferred Income Taxes	(241,948)	141,668	(100,280)	0	(100,280)
21	Accumulated Deferred Inv. Tax Credit	(50,164)	8,252	(41,912)	0	(41,912)
22	**Net Utility Plant**	$1,286,565	$65,692	$1,352,257	$0	$1,352,257
23	Energy Efficiency	59,853	47,856	107,709	0	107,709
24	Boardman Gain	(60,904)	(54,916)	(115,820)	0	(115,820)
25	Deferred Trojan Investment	268,921	(44,082)	224,839	0	224,839
26	Materials & Supplies - Fuel	14,810	0	14,810	0	14,810
27	- Other	27,205	(5,827)	21,378	0	21,378
28	Working Cash	39,388	(1,882)	37,506	1,036	38,542
29	Misc. Deferred Debits	27,498	0	27,498	0	27,498
30	Misc. Deferred Credits	(16,196)	2,931	(13,265)	0	(13,265)
31	**Total Average Rate Base**	$1,647,140	$9,772	$1,656,912	$1,036	$1,657,947
32	**of Return**	5.84%		7.63%		0%
33	**ed Return on Equity**	3.08%		7.36%		%

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Miscellaneous Corrections to Company Filing					
		PGC Inflation (S-1)	EPRI Deferral (S-2)	Category "C" Advertising (S-3)	Retirement Savings Plan (S-4)	Legal Escalation (S-5)	Health Insurance Escalation (S-6)
1	Operating Revenues						
2	Sales to Consumers	$0	$0	$0	$0	$0	$0
3	Other Revenues		0				
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes						
6	Operation & Maintenance						
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs						
9	Other Oper.& Maint.	(628)	0	(24)	(1,488)	(160)	(702)
10	**Total Operation & Maintenance**	($628)	$0	($24)	($1,488)	($160)	($702)
11	Depreciation & Amortization	0	0	0	0	0	0
12	Taxes Other than Income	(15)	0	0	0	0	0
13	Income Taxes	254	(0)	9	588	63	277
14							
15	**Total Operating Expenses and Taxes**	($389)	($0)	($15)	($900)	($97)	($425)
16	**Utility Operating Income**	$389	$0	$15	$900	$97	$425
17	Average Rate Base						
18	Utility Plant in Service	$0	$0	$0	$0	$0	$0
19	Accumulated Depreciation	0	0	0	0	0	0
20	Accumulated Deferred Income Taxes	0	0	0	0	0	0
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	$0
23	Energy Efficiency						
24	Boardman Gain	0	0	0	0	0	0
25	Trojan Investment						
26	Materials & Supplies - Fuel						
27	- Other						
28	Working Cash	(18)	(0)	(1)	(41)	(4)	(19)
29	Misc. Deferred Debits						
30	Misc. Deferred Credits						
31	**Total Average Rate Base**	($18)	($0)	($1)	($41)	($4)	($19)
32	**Revenue Requirement Effect**	($662)	$0	($25)	($1,532)	($165)	($723)

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Miscellaneous Corrections to Company Filing						
		Overhead Billing (S-7)	Service Provider Costs (S-8)	WTC Improvements (S-9)	Managers/Dir. Def. Comp. (S-10)	Income Tax Adjustments (S-11)	Load Forecast (S-12)	Variable Power Costs (S-13)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$1,854	$0
3	Other Revenues	688						
4	**Total Operating Revenues**	$688	$0	$0	$0	$0	$1,854	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$1,198	($59,543)
8	Fixed Power Costs							
9	Other Oper.& Maint.	(71)	2,953	0	808	0	239	0
10	**Total Operation & Maintenance**	($71)	$2,953	$0	$808	$0	$1,437	($59,543)
11	Depreciation & Amortization	0					75	
12	Taxes Other than Income	0	0	0	0	0	68	0
13	Income Taxes	299	(1,166)	(6)	(319)	(607)	80	23,516
14								
15	**Total Operating Expenses and Taxes**	$228	$1,787	($6)	$489	($607)	$1,660	($36,027)
16	**Utility Operating Income**	$460	($1,787)	$6	($489)	$607	$194	$36,027
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$690	$0	$0	$1,863	$0
19	Accumulated Depreciation	0		(276)			(75)	
20	Accumulated Deferred Income Taxes	0				3,483	0	
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$414	$0	$3,483	$1,788	$0
23	Energy Efficiency	0	0	0	0	0		0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other			0		0		0
28	Working Cash	10	81	(0)	22	(28)	76	(1,788)
29	Misc. Deferred Debits	0						
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	$10	$81	$414	$22	$3,455	$1,864	($1,788)
32	**Revenue Requirement Effect**	($777)	$3,041	$57	$832	($467)	($26)	($61,334)

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Miscellaneous Electric Revenues (S-14)	Wage & Salary Adjustment (S-15)	Incentive Pay Adjustment (S-16)	Supplemental Executive Retirement (S-17)	Managers' Deferred Compensation (S-18)	Directors' Deferred Comp. & Pensions (S-19)	Medical Insurance (S-20)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues	1,504						
4	**Total Operating Revenues**	$1,504	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	(702)	(3,861)	(2,046)	(2,172)	(194)	(748)
10	**Total Operation & Maintenance**	$0	($702)	($3,861)	($2,046)	($2,172)	($194)	($748)
11	Depreciation & Amortization	0	0		0			0
12	Taxes Other than Income	0	(77)	(425)	0	0	0	0
13	Income Taxes	593	311	1,692	772	850	77	300
14								
15	**Total Operating Expenses and Taxes**	$593	($468)	($2,593)	($1,274)	($1,322)	($117)	($448)
16	**Utility Operating Income**	$911	$468	$2,593	$1,274	$1,322	$117	$448
17	Average Rate Base							
18	Utility Plant in Service	$0	($233)	$0	$0	$0	$0	($276)
19	Accumulated Depreciation	0		0		0		0
20	Accumulated Deferred Income Taxes	0		0		0		0
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	($233)	$0	$0	$0	$0	($276)
23	Energy Efficiency		0		0		0	
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other		0		0		0	
28	Working Cash	27	(21)	(118)	(58)	(60)	(5)	(20)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits				2,389	542	0	
31	**Total Average Rate Base**	$27	($254)	($118)	$2,331	$482	($5)	($296)
32	**Revenue Requirement Effect**	($1,539)	($834)	($4,413)	($1,780)	($2,162)	($200)	($808)

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		EPRI Membership Replacement (S-21)	Escalation Rate Update (S-22)	Non-Labor Cust. Accts, (S-23)	Community Development (S-24)	Market Intelligence (S-25)	CS2 Project (S-26)	Advertising Category "A" (S-27)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues							
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	(1,594)	(108)	(286)	(212)	(700)	(373)
10	**Total Operation & Maintenance**	$0	($1,594)	($108)	($286)	($212)	($700)	($373)
11	Depreciation & Amortization			0			(2,562)	
12	Taxes Other than Income	0	0	0	(16)	(16)	0	0
13	Income Taxes	(0)	629	43	119	90	1,369	147
14								
15	**Total Operating Expenses and Taxes**	($0)	($965)	($65)	($183)	($138)	($1,893)	($226)
16	**Utility Operating Income**	$0	$965	$65	$183	$138	$1,893	$226
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	$0	($8,400)	$0
19	Accumulated Depreciation			0			1,469	
20	Accumulated Deferred Income Taxes			0			(490)	
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	($7,421)	$0
23	Energy Efficiency	0	0	0	0	0	0	0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other	0	0					
28	Working Cash	(0)	(44)	(3)	(8)	(6)	(86)	(10)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	($0)	($44)	($3)	($8)	($6)	($7,507)	($10)
32	**Revenue Requirement Effect**	$0	($1,641)	($111)	($311)	($235)	($4,428)	($384)

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Power Smart (S-28)	HVEA Promotions (S-29)	Energy Resource Center (ERC) (S-30)	Energy Efficiency (S-31)	PGC Allocation (S-32)	Equity Issuance Costs (S-33)	Payroll Tax Rate (S-34)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	($12,226)	$0	$0	$0
3	Other Revenues			0	244			
4	**Total Operating Revenues**	$0	$0	$0	($11,982)	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	($8,079)	$0	$0	$0
8	Fixed Power Costs		0	0			0	
9	Other Oper.& Maint.	(112)	(1,449)	(211)	3,143	(210)	0	
10	**Total Operation & Maintenance**	($112)	($1,449)	($211)	($4,936)	($210)	$0	$0
11	Depreciation & Amortization						(2,100)	
12	Taxes Other than Income	(5)	(61)	0	(257)	0	0	(379)
13	Income Taxes	46	596	83	(3,394)	83	1	151
14								
15	**Total Operating Expenses and Taxes**	($71)	($914)	($128)	($8,586)	($127)	($2,099)	($228)
16	**Utility Operating Income**	$71	$914	$128	($3,396)	$127	$2,099	$228
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	$0	$0	($81)
19	Accumulated Depreciation							
20	Accumulated Deferred Income Taxes				0			
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	$0	($81)
23	Energy Efficiency	0	0	0	47,856	0	0	0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment			0				
26	Materials & Supplies - Fuel							
27	- Other					0		
28	Working Cash	(3)	(42)	(6)	(391)	(6)	(95)	(10)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	($3)	($42)	($6)	$47,465	($6)	($95)	($91)
32	**Revenue Requirement Effect**	($120)	($1,555)	($217)	$13,473	($216)	($3,571)	($401)

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Revised Interest from ROR Change (S-35)	Non-Fuel Materials & Supplies (S-36)	Remove Boardman Gain Accel. (S-37)	Trojan Overtime (S-45)	Trojan Plant Reclassification (S-46)	Trojan Salvage Recovery (S-47)	Decommissioning Trust Accrual Reduction (S-48)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues							
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	0	0	(310)	0	0	0
10	**Total Operation & Maintenance**	$0	$0	$0	($310)	$0	$0	$0
11	Depreciation & Amortization			36,417	0	0	(353)	(1,072)
12	Taxes Other than Income	0	0	0	(34)	0	0	0
13	Income Taxes	644	16	(14,888)	139	0	189	390
14								
15	**Total Operating Expenses and Taxes**	$644	$16	$21,529	($205)	$0	($164)	($682)
16	**Utility Operating Income**	($644)	($16)	($21,529)	$205	$0	$164	$682
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	($200)	($155,182)	$0	$0
19	Accumulated Depreciation			0	0	77,634	0	0
20	Accumulated Deferred Income Taxes			22,149	0	93,796	0	(1,627)
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	8,252	0	0
22	**Net Utility Plant**	$0	$0	$22,149	($200)	$24,500	$0	($1,627)
23	Energy Efficiency	0	0					
24	Boardman Gain	0	0	(54,916)	0	0	0	0
25	Trojan Investment					(19,762)	(3,315)	3,908
26	Materials & Supplies - Fuel							
27	- Other		(1,089)			(4,738)		
28	Working Cash	29	1	980	(9)	0	(7)	(31)
29	Misc. Deferred Debits			0	0	0	0	0
30	Misc. Deferred Credits			0	0	0	0	0
31	**Total Average Rate Base**	$29	($1,088)	($31,787)	($209)	$0	($3,322)	$2,250
32	**Revenue Requirement Effect**	$1,095	($149)	$31,309	($382)	$0	($818)	($789)

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Remove Plugging, Sleeving, Analysis & Reactor Pump (S-49)	Remove Additional Trojan Fixed Costs to Reach 86.9% (S-50)	Remove Trojan Power Cost Deferral (S-51)	Update Trojan Plant Income Tax Write-off (S-52)	Trojan Intangible Asset (S-53)	Reduce Discretionary Costs by 1%	Total Adjustments
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	($10,372)
3	Other Revenues							2,436
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	($7,936)
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	($66,424)
8	Fixed Power Costs							0
9	Other Oper.& Maint.	0	(9)	0	0	0	(1,639)	(12,865)
10	**Total Operation & Maintenance**	$0	($9)	$0	$0	$0	($1,639)	(79,289)
11	Depreciation & Amortization	(1,638)	(1,921)	0	0	0	0	26,846
12	Taxes Other than Income	0	(250)	0	0	0	0	(1,467)
13	Income Taxes	893	725	(367)	(115)	0	647	15,821
14								
15	**Total Operating Expenses and Taxes**	($745)	($1,455)	($367)	($115)	$0	($992)	($38,089)
16	**Utility Operating Income**	$745	$1,455	$367	$115	$0	$992	$30,153
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	($1,162)	$0	($162,981)
19	Accumulated Depreciation	0	0	0	0	0	0	78,752
20	Accumulated Deferred Income Taxes	0	0	24,357	0	0	0	141,668
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	8,252
22	**Net Utility Plant**	$0	$0	$24,357	$0	($1,162)	$0	$65,692
23	Energy Efficiency							47,856
24	Boardman Gain	0	0	0	0	0	0	(54,916)
25	Trojan Investment	(15,619)	(18,536)		8,080	1,162	0	(44,082)
26	Materials & Supplies - Fuel							0
27	- Other							(5,827)
28	Working Cash	(34)	(66)	(17)	(5)	0	(45)	(1,882)
29	Misc. Deferred Debits	0	0	0	0	0	0	0
30	Misc. Deferred Credits	0	0	0	0	0	0	2,931
31	**Total Average Rate Base**	($15,653)	($18,602)	$24,340	$8,075	$0	($45)	$9,772
32	**Revenue Requirement Effect**	($3,808)	($5,491)	$3,337	$1,119	$0	($1,687)	($49,501)

23-Mar-95
05:45 PM

PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1996
(000)

Income Tax Calculations	1996 Per Company Filing (1)	Adjustments (2)	1996 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
Book Revenues	$918,919	($7,936)	$910,983	$55,550	$966,533
Book Expenses Other than Depreciation	654,024	(80,756)	573,268	1,406	574,674
State Tax Depreciation	124,955	(4,556)	120,399		120,399
Interest	64,570	(1,259)	63,311	40	63,350
Book-Tax (Schedule M) Differences	(27,907)	(3,252)	(31,159)		(31,159)
State Taxable Income	$103,277	$81,887	$185,164	$54,104	$239,269
State Income Tax @ 6.672%	$6,903	$5,464	$12,367	$3,610	$15,977
State Tax Credit	83	0	83		83
Net State Income Tax	$6,820	$5,464	$12,284	$3,610	$15,894
Additional Tax Depreciation	0	0	0		0
Other Schedule M Differences	0	0	0		0
Federal Taxable Income	$96,985	$75,896	$172,881	$50,494	$223,375
Federal Tax @ 35%	$33,946	$26,564	$60,510	$17,683	$78,193
ITC	0	0	0	0	0
Current Federal Tax	$33,946	$26,564	$60,510	$17,683	$78,193
Environmental Tax @ 0.12%	$93	$91	$184	61	$245
ITC Adjustment					
Deferral	$0	$0	$0	$0	$0
Restoration	2,039	(54)	1,985		1,985
Total ITC Adjustment	($2,039)	$54	($1,985)	$0	($1,985)
Provision for Deferred Taxes	$4,928	($16,351)	($11,423)	$0	($11,423)
Total Income Tax	$43,748	$15,821	$59,569	$21,354	$80,923

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Miscellaneous Corrections to Company Filing					
	Income Tax Calculations	PGC Inflation (S-1)	EPRI Deferral (S-2)	Category 'C' Advertising (S-3)	Retirement Savings Plan (S-4)	Legal Escalation (S-5)	Health Insurance Escalation (S-6)
33	Book Revenues	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	(643)	0	(24)	(1,488)	(160)	(702)
35	State Tax Depreciation	0	0	0	0	0	0
36	Interest	(1)	(0)	(0)	(2)	(0)	(1)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0
38	State Taxable Income	$644	$0	$24	$1,490	$160	$703
39	State Income Tax @ 6.672%	$43	$0	$2	$99	$11	$47
40	State Tax Credit						
41	**Net State Income Tax**	**$43**	**$0**	**$2**	**$99**	**$11**	**$47**
42	Additional Tax Depreciation	0	0	0	0	0	0
43	Other Schedule M Differences						
44	Federal Taxable Income	$601	$0	$22	$1,390	$149	$656
45	Federal Tax @ 35%	$210	$0	$8	$487	$52	$230
46	ITC	0	0	0	0	0	0
47	**Current Federal Tax**	**$210**	**$0**	**$8**	**$487**	**$52**	**$230**
48	**Environmental Tax @ 0.12%**	**$1**	**$0**	**$0**	**$2**	**$0**	**$1**
49	ITC Adjustment						
50	Deferral	$0	$0	$0	$0	$0	$0
51	Restoration						
52	**Total ITC Adjustment**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
53	**Provision for Deferred Taxes**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
54	**Total Income Tax**	**$254**	**$0**	**$9**	**$588**	**$63**	**$277**

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Miscellaneous Corrections to Company Filing						
		Overhead Billing (S-7)	Service Provider Costs (S-8)	WTC Improvements (S-9)	Managers/Dir. Def. Comp. (S-10)	Income Tax Adjustments (S-11)	Load Forecast (S-12)	Variable Power Costs (S-13)
33	Book Revenues	$688	$0	$0	$0	$0	$1,854	$0
34	Book Expenses Other than Depreciation	(71)	2,953	0	808	0	1,505	(59,543)
35	State Tax Depreciation	0	0	0	0	0	75	0
36	Interest	0	3	16	1	132	71	(68)
37	Book-Tax (Schedule M) Differences	0	0	0	0	(1,740)	0	0
38	State Taxable Income	$759	($2,956)	($16)	($809)	$1,608	$203	$59,611
39	State Income Tax @ 6.672%	$51	($197)	($1)	($54)	$107	$14	$3,977
40	State Tax Credit							
41	**Net State Income Tax**	$51	($197)	($1)	($54)	$107	$14	$3,977
42	Additional Tax Depreciation	0	0	0	0		0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$708	($2,759)	($15)	($755)	$973	$189	$55,634
45	Federal Tax @ 35%	$248	($966)	($5)	($264)	$340	$66	$19,472
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$248	($966)	($5)	($264)	$340	$66	$19,472
48	**Environmental Tax @ 0.12%**	$1	($3)	($0)	($1)	$1	$0	$67
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	($1,056)	$0	$0
54	**Total Income Tax**	$299	($1,166)	($6)	($319)	($607)	$80	$23,516

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Miscellaneous Electric Revenues (S-14)	Wage & Salary Adjustment (S-15)	Incentive Pay Adjustment (S-16)	Supplemental Executive Retirement (S-17)	Managers' Deferred Compensation (S-18)	Directors' Deferred Comp. & Pensions (S-19)	Medical Insurance (S-20)
33	Book Revenues	$1,504	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	(779)	(4,286)	(2,046)	(2,172)	(194)	(748)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	1	(10)	(5)	89	18	(0)	(11)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$1,503	$789	$4,290	$1,957	$2,154	$194	$759
39	State Income Tax @ 6.672%	$100	$53	$286	$131	$144	$13	$51
40	State Tax Credit							
41	**Net State Income Tax**	**$100**	**$53**	**$286**	**$131**	**$144**	**$13**	**$51**
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$1,403	$736	$4,004	$1,826	$2,010	$181	$709
45	Federal Tax @ 35%	$491	$258	$1,401	$639	$703	$63	$248
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	**$491**	**$258**	**$1,401**	**$639**	**$703**	**$63**	**$248**
48	**Environmental Tax @ 0.12%**	**$2**	**$1**	**$5**	**$2**	**$2**	**$0**	**$1**
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
53	**Provision for Deferred Taxes**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
54	**Total Income Tax**	**$593**	**$311**	**$1,692**	**$772**	**$850**	**$77**	**$300**

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	EPRI Membership Replacement (S-21)	Escalation Rate Update (S-22)	Non-Labor Cust. Accts, (S-23)	Community Development (S-24)	Market Intelligence (S-25)	CS2 Project (S-26)	Advertising Category "A" (S-27)
33	Book Revenues	$0	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	(1,594)	(108)	(302)	(228)	(700)	(373)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	(0)	(2)	(0)	(0)	(0)	(287)	(0)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$0	$1,596	$108	$302	$228	$987	$373
39	State Income Tax @ 6.672%	$0	$106	$7	$20	$15	$66	$25
40	State Tax Credit							
41	**Net State Income Tax**	$0	$106	$7	$20	$15	$66	$25
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$0	$1,489	$101	$282	$213	$921	$348
45	Federal Tax @ 35%	$0	$521	$35	$99	$75	$322	$122
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$0	$521	$35	$99	$75	$322	$122
48	**Environmental Tax @ 0.12%**	$0	$2	$0	$0	$0	$1	$0
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$980	$0
54	**Total Income Tax**	$0	$629	$43	$119	$90	$1,369	$147

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Power Smart (S-28)	HVEA Promotions (S-29)	Energy Resource Center (ERC) (S-30)	Energy Efficiency (S-31)	PGC Alloc/Inflation (S-32)	Equity Issuance Costs (S-33)	Payroll Tax Rate (S-34)
33	Book Revenues	$0	$0	$0	($11,982)	$0	$0	$0
34	Book Expenses Other than Depreciation	(117)	(1,510)	(211)	(5,192)	(210)	0	(379)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	(0)	(2)	(0)	1,814	(0)	(4)	(3)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$117	$1,512	$211	($8,603)	$210	$4	$382
39	State Income Tax @ 6.672%	$8	$101	$14	($574)	$14	$0	$26
40	State Tax Credit							
41	**Net State Income Tax**	**$8**	**$101**	**$14**	**($574)**	**$14**	**$0**	**$26**
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$109	$1,411	$197	($8,029)	$196	$3	$357
45	Federal Tax @ 35%	$38	$494	$69	($2,810)	$69	$1	$125
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	**$38**	**$494**	**$69**	**($2,810)**	**$69**	**$1**	**$125**
48	**Environmental Tax @ 0.12%**	**$0**	**$2**	**$0**	**($10)**	**$0**	**$0**	**$0**
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
53	**Provision for Deferred Taxes**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
54	**Total Income Tax**	**$46**	**$596**	**$83**	**($3,394)**	**$83**	**$1**	**$151**

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Revised Interest from ROR Change (S-35)	Non-Fuel Materials & Supplies (S-36)	Remove Boardman Gain Accel. (S-37)	Trojan Overtime (S-45)	Trojan Plant Reclassification (S-46)	Trojan Salvage Recovery (S-47)	Decommissioning Trust Accrual Reduction (S-48)
33	Book Revenues	$0	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	0	0	(344)	0	0	0
35	State Tax Depreciation	0	0	0	0	0	0	(1,072)
36	Interest	(1,632)	(42)	(1,215)	(8)	0	(127)	86
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	(1,517)
38	State Taxable Income	$1,632	$42	$1,215	$352	$0	$127	$2,503
39	State Income Tax @ 6.672%	$109	$3	$81	$23	$0	$8	$167
40	State Tax Credit							
41	**Net State Income Tax**	$109	$3	$81	$23	$0	$8	$167
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences	0		0	0	0	0	0
44	Federal Taxable Income	$1,523	$39	$1,134	$329	$0	$118	$2,336
45	Federal Tax @ 35%	$533	$14	$397	$115	$0	$41	$818
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$533	$14	$397	$115	$0	$41	$818
48	**Environmental Tax @ 0.12%**	$2	$0	$1	$0	$0	$0	$3
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	($15,367)	$0	$0	$139	($597)
54	**Total Income Tax**	$644	$16	($14,888)	$139	$0	$189	$390

23-Mar-95
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Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Remove Plugging, Sleeving, Analysis & Reactor Pump (S-49)	Remove Additional Trojan Fixed Costs to Reach 86.9% (S-50)	Remove Trojan Power Cost Deferral (S-51)	Update Trojan Plant Income Tax Write-off (S-52)	Trojan Intangible Asset (S-53)	Reduce Discretionary Costs by 1%	Total Adjustments
33	Book Revenues	$0	$0	$0	$0	$0	$0	($7,936)
34	Book Expenses Other than Depreciation	0	(259)	0	0	0	(1,639)	($80,756)
35	State Tax Depreciation	0	(3,559)	0	0	0	0	($4,556)
36	Interest	(598)	(711)	930	309	0	(2)	($1,259)
37	Book-Tax (Schedule M) Differences	0	4,474	0	(4,469)	0	0	($3,252)
38	State Taxable Income	$598	$55	($930)	$4,160	$0	$1,640	$81,887
39	State Income Tax @ 6.672%	$40	$4	($62)	$278	$0	$109	$5,464
40	State Tax Credit							$0
41	**Net State Income Tax**	**$40**	**$4**	**($62)**	**$278**	**$0**	**$109**	**$5,464**
42	Additional Tax Depreciation	0	0	0	0	0	0	$0
43	Other Schedule M Differences	0	0	0	0	0	0	$0
44	Federal Taxable Income	$558	$51	($868)	$3,883	$0	$1,531	$75,896
45	Federal Tax @ 35%	$195	$18	($304)	$1,359	$0	$536	$26,564
46	ITC	0	0	0	0	0	0	$0
47	**Current Federal Tax**	**$195**	**$18**	**($304)**	**$1,359**	**$0**	**$536**	**$26,564**
48	**Environmental Tax @ 0.12%**	**$1**	**$0**	**($1)**	**$5**	**$0**	**$2**	**$91**
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration		(54)					($54)
52	**Total ITC Adjustment**	**$0**	**$54**	**$0**	**$0**	**$0**	**$0**	**$54**
53	**Provision for Deferred Taxes**	**$657**	**$649**	**$0**	**($1,756)**	**$0**	**$0**	**($16,351)**
54	**Total Income Tax**	**$893**	**$725**	**($367)**	**($115)**	**$0**	**$647**	**$15,821**

PORTLAND GENERAL ELECTRIC CO.
General Rate Case - UE 88
(000)

COST OF CAPITAL - 1996	AMOUNTS	% OF CAPITAL	COST	WEIGHTED COST
Long Term Debt	$1,044,215	48.86%	7.82%	3.82%
Preferred Stock	99,703	4.67%	8.27%	0.39%
Common Equity	993,333	46.47%	11.60%	5.39%
Total	$2,137,251	100.00%		9.60%

REVENUE SENSITIVE COSTS	
Revenues	1.00000
O&M - Uncollectible/OPUC Fee*	0.00430
Other Taxes-Franchise	0.02100
Short-Term Interest	0.00000
Other Taxes	0.00000
State Taxable Income	0.97470
State Income Tax @ 6.672%**	0.06503
Federal Taxable Income	0.90967
Federal Income Tax @ 35%	0.31838
ITC	0.00000
Current FIT	0.31838
ITC Adjustment/Env. Tax	0.00109
Total Income Taxes	0.38451
Total Revenue Sensitive Costs	0.40981
Utility Operating Income	0.59019
Net-to-Gross Factor	1.69436

* Uncollectible Rate	0.00230
OPUC	0.00200
Total	0.00430

** State Income Tax	
Montana (.0675*.050008)	0.00338
Oregon (.0660*.959764)	0.06334
Total	0.06672

95-322

PORTLAND GENERAL ELECTRIC COMPANY
RATE DESIGN SUMMARY TABLE FORECAST STFPUC94
25-Mar-95 MONTHLY REVENUE MODEL SCH102 at PF-93 Rate

For CALENDAR Years
1995-96 Test Period

CUSTOMER CLASSIFICATION	RATE SCHEDULE	AVERAGE CUSTOMERS	KWH SALES (000'S)	REVENUES BEFORE RPA E-15 PH I W/O ADJUSTMENTS	REVENUES BEFORE RPA E-16 PH I W/O ADJUSTMENTS	INCREASE IN REVENUES AMOUNT	INCREASE IN REVENUES PERCENT
RESIDENTIAL:							
SERVICE	7	569,338	13,811,054	$809,727,203	$882,204,684	$72,477,481	9.0%
OUTDOOR LIGHTING RES	14R	(670)	7,904	1,336,018	1,309,255	(26,763)	-2.0%
REVENUE CLASS TOTAL		569,338	13,818,958	$811,063,221	$883,513,938	$72,450,718	8.9%
GENERAL SERVICE:							
OUTDOOR LIGHTING FARM	14C	(269)	4,734	$756,322	$736,181	($20,141)	-2.7%
OUTDOOR LIGHTING GEN SER	15C	(864)	27,531	3,098,909	3,046,847	(52,062)	-1.7%
FARM & RESIDENTIAL GEN SER							
DEMAND LEVEL I	31-I	17,245	417,967	$27,034,536	$28,920,340	$1,885,804	7.0%
DEMAND LEVEL II	31-II	892	478,311	23,752,243	24,502,341	750,099	3.2%
DEMAND LEVEL III (TOD)	31-III	1	25,631	1,182,164	1,179,651	(2,514)	-0.2%
GENERAL SECONDARY VOLTAGE							
DEMAND LEVEL I	32-I	45,972	1,940,248	119,151,360	125,889,649	6,738,289	5.7%
DEMAND LEVEL II	32-II	9,179	7,721,341	381,580,267	394,423,914	12,843,647	3.4%
DEMAND LEVEL III (TOD)	32-III	126	1,621,316	76,912,393	78,285,588	1,373,195	1.8%
TOTAL 31 & 32		73,414	12,204,815	$629,612,962	$653,201,483	$23,588,521	3.7%
FARM AND RES OPTIONAL (TOD)	37	12	1,992	111,422	111,944	522	0.5%
GEN SER OPTIONAL (TOD)	38	205	119,709	6,624,303	6,774,245	149,942	2.3%
IRRIG AND DRAINAGE FARM	48	4,347	139,992	6,524,501	7,122,771	598,270	9.2%
IRRIG AND DRAINAGE OTHER	49	139	13,955	599,766	638,681	38,916	6.5%
DRAINAGE DISTRICTS	97	2	1,522	68,306	72,337	4,031	5.9%
REVENUE CLASS TOTAL		78,119	12,514,250	$647,396,491	$671,704,490	$24,307,999	3.8%
LARGE GENERAL SERVICE:							
FARM & RESIDENTIAL LGS							
DEMAND LEVEL I	82-I	2	11,599	$524,437	$526,857	$2,419	0.5%
DEMAND LEVEL II (TOD)	82-II	1	9,614	463,172	470,966	7,794	1.7%
GENERAL PRIMARY VOLTAGE							
DEMAND LEVEL I	83-I	66	336,557	15,378,330	15,507,419	129,089	0.8%
DEMAND LEVEL II (TOD)	83-II	107	3,410,621	152,166,305	152,712,972	546,666	0.4%
TOTAL 82 & 83		176	3,768,392	$168,532,245	$169,218,213	$685,969	0.4%
LARGE INDUSTRIAL (TOD):							
TRANSMISSION VOLTAGE	89	2	454,521	$18,832,864	$18,193,332	($639,532)	-3.4%
STREETLIGHTING:							
STREET AND HIGHWAY LIGHTING	91	547	158,501	$21,348,168	$20,801,275	($546,893)	-2.6%
TRAFFIC SIGNALS	92	96	34,719	1,714,755	1,816,133	101,379	5.9%
RECREATIONAL FIELD LIGHTING	93	34	1,150	101,039	107,005	5,966	5.9%
REVENUE CLASS TOTAL		677	194,370	$23,163,962	$22,724,413	($439,549)	-1.9%
CONTRACTUAL SALES	99	5	3,681,231	$117,304,965	$123,744,583	$6,439,618	5.5%
REVENUE ADJUSTMENTS	-	-	(6,833)	($828,000)	($828,000)		
EMPLOYEE DISCOUNT	-	-	-	(1,346,924)	(1,435,070)		
TOTAL (CYCLE YEAR BASIS)		648,317	34,424,889	$1,784,118,824	$1,886,835,900	$102,717,076	5.8%
CONVERSION ADJ. - CYCLE TO CALENDAR YEAR			36,908	1,813,075	1,878,601		
TOTAL ULTIMATE SALES (CALENDAR YEAR BASIS)			34,461,797	$1,785,931,899	$1,888,714,501	$102,782,602	5.8%

PORTLAND GENERAL ELECTRIC COMPANY
RATE DESIGN SUMMARY TABLE FORECAST STFPUC94
27-Mar-95 MONTHLY REVENUE MODEL SCH102 at PF-93 Rate

For CALENDAR Years
1995-96 Test Period

CUSTOMER CLASSIFICATION	RATE SCHEDULE	AVERAGE CUSTOMERS	KWH SALES (000'S)	REVENUES AFTER RPA E-15 PH I W/O ADJUSTMENTS	REVENUES AFTER RPA E-16 PH I W/O ADJUSTMENTS	INCREASE IN REVENUES AMOUNT	INCREASE IN REVENUES PERCENT
RESIDENTIAL:							
SERVICE	7	569,338	13,811,054	$727,689,539	$785,112,971	$57,423,432	7.9%
OUTDOOR LIGHTING RES	14R	(670)	7,904	1,289,071	1,253,692	(35,378)	-2.7%
REVENUE CLASS TOTAL		569,338	13,818,958	$728,978,610	$786,366,664	$57,388,053	7.9%
GENERAL SERVICE:							
OUTDOOR LIGHTING FARM	14C	(269)	4,734	$728,199	$702,898	($25,301)	-3.5%
OUTDOOR LIGHTING GEN SER	15C	(864)	27,531	2,912,522	3,046,847	134,325	4.6%
FARM & RESIDENTIAL GEN SER							
DEMAND LEVEL I	31-I	17,245	417,967	$24,551,811	$25,982,031	$1,430,220	5.8%
DEMAND LEVEL II	31-II	892	478,311	20,911,191	21,139,816	228,625	1.1%
DEMAND LEVEL III (TOD)	31-III	1	25,631	1,029,913	999,461	(30,452)	-3.0%
GENERAL SECONDARY VOLTAGE							
DEMAND LEVEL I	32-I	45,972	1,940,248	119,151,360	125,889,649	6,738,289	5.7%
DEMAND LEVEL II	32-II	9,179	7,721,341	381,576,960	394,423,914	12,846,954	3.4%
DEMAND LEVEL III (TOD)	32-III	126	1,621,316	76,912,393	78,285,588	1,373,195	1.8%
TOTAL 31 & 32		73,414	12,204,815	$624,133,628	$646,720,460	$22,586,831	3.6%
FARM AND RES OPTIONAL (TOD)	37	12	1,992	99,591	97,942	(1,649)	-1.7%
GEN SER OPTIONAL (TOD)	38	205	119,709	6,624,303	6,774,245	149,942	2.3%
IRRIG AND DRAINAGE FARM	48	4,347	139,992	5,692,952	6,138,631	445,679	7.8%
IRRIG AND DRAINAGE OTHER	49	139	13,955	599,766	638,681	38,916	6.5%
DRAINAGE DISTRICTS	97	2	1,522	68,306	72,337	4,031	5.9%
REVENUE CLASS TOTAL		78,119	12,514,250	$640,859,268	$664,192,042	$23,332,774	3.6%
LARGE GENERAL SERVICE:							
FARM & RESIDENTIAL LGS							
DEMAND LEVEL I	82-I	2	11,599	$455,540	$445,317	($10,223)	-2.2%
DEMAND LEVEL II (TOD)	82-II	1	9,614	406,063	403,378	(2,685)	-0.7%
GENERAL PRIMARY VOLTAGE							
DEMAND LEVEL I	83-I	66	336,557	15,378,330	15,507,419	129,089	0.8%
DEMAND LEVEL II (TOD)	83-II	107	3,410,621	152,166,305	152,712,972	546,666	0.4%
TOTAL 82 & 83		176	3,768,392	$168,406,239	$169,069,085	$662,846	0.4%
LARGE INDUSTRIAL (TOD):							
TRANSMISSION VOLTAGE	89	2	454,521	$18,832,864	$18,193,332	($639,532)	-3.4%
STREETLIGHTING:							
STREET AND HIGHWAY LIGHTING	91	547	158,501	$21,348,168	$20,801,275	($546,893)	-2.6%
TRAFFIC SIGNALS	92	96	34,719	1,714,755	1,816,133	101,379	5.9%
RECREATIONAL FIELD LIGHTING	93	34	1,150	101,039	107,005	5,966	5.9%
REVENUE CLASS TOTAL		677	194,370	$23,163,962	$22,724,413	($439,549)	-1.9%
CONTRACTUAL SALES	99	5	3,681,231	$117,304,965	$123,744,583	$6,439,618	5.5%
REVENUE ADJUSTMENTS	-	-	(6,833)	($828,000)	($828,000)		
EMPLOYEE DISCOUNT	-	-	-	(1,111,007)	(1,162,059)		
TOTAL (CYCLE YEAR BASIS)		648,317	34,424,889	$1,695,606,901	$1,782,300,060	$86,693,159	5.1%
CONVERSION ADJ. - CYCLE TO CALENDAR YEAR			36,908	1,734,798	1,714,874		
TOTAL ULTIMATE SALES (CALENDAR YEAR BASIS)			34,461,797	$1,697,341,699	$1,784,014,934	$86,673,235	5.1%

95-322

PORTLAND GENERAL ELECTRIC COMPANY
RATE DESIGN SUMMARY TABLE FORECAST STFPUC94
25-Mar-95 MONTHLY REVENUE MODEL SCH102 at PF-93 Rate

For CALENDAR Years
1995-96 Test Period

CUSTOMER CLASSIFICATION	RATE SCHEDULE	AVERAGE CUSTOMERS	KWH SALES (000'S)	REVENUES AFTER RPA E-15 PH I With Adjustments	REVENUES AFTER RPA E-16 PH I With Adjustments	INCREASE IN REVENUES AMOUNT	INCREASE IN REVENUES PERCENT
RESIDENTIAL:							
SERVICE	7	569,338	13,811,054	$743,986,584	$801,410,015	$57,423,432	7.7%
OUTDOOR LIGHTING RES	14R	(670)	7,904	1,292,153	1,256,775	(35,378)	-2.7%
REVENUE CLASS TOTAL		569,338	13,818,958	$745,278,737	$802,666,790	$57,388,053	7.7%
GENERAL SERVICE:							
OUTDOOR LIGHTING FARM	14C	(269)	4,734	$730,046	$704,745	($25,301)	-3.5%
OUTDOOR LIGHTING GEN SER	15C	(864)	27,531	2,946,111	3,080,435	134,325	4.6%
FARM & RESIDENTIAL GEN SER							
DEMAND LEVEL I	31-I	17,245	417,967	$24,781,693	$26,211,913	$1,430,220	5.8%
DEMAND LEVEL II	31-II	892	478,311	20,686,385	20,915,010	228,625	1.1%
DEMAND LEVEL III (TOD)	31-III	1	25,631	1,017,867	987,415	(30,452)	-3.0%
GENERAL SECONDARY VOLTAGE							
DEMAND LEVEL I	32-I	45,972	1,940,248	121,828,903	128,567,192	6,738,289	5.5%
DEMAND LEVEL II	32-II	9,179	7,721,341	384,356,642	397,203,597	12,846,954	3.3%
DEMAND LEVEL III (TOD)	32-III	126	1,621,316	77,496,067	78,869,262	1,373,195	1.8%
TOTAL 31 & 32		73,414	12,204,815	$630,167,557	$652,754,388	$22,586,831	3.6%
FARM AND RES OPTIONAL (TOD)	37	12	1,992	98,735	97,086	(1,649)	-1.7%
GEN SER OPTIONAL (TOD)	38	205	119,709	6,672,186	6,822,129	149,942	2.2%
IRRIG AND DRAINAGE FARM	48	4,347	139,992	5,796,546	6,242,224	445,679	7.7%
IRRIG AND DRAINAGE OTHER	49	139	13,955	621,675	660,590	38,916	6.3%
DRAINAGE DISTRICTS	97	2	1,522	69,843	73,874	4,031	5.8%
REVENUE CLASS TOTAL		78,119	12,514,250	$647,102,698	$670,435,472	$23,332,774	3.6%
LARGE GENERAL SERVICE:							
FARM & RESIDENTIAL LGS							
DEMAND LEVEL I	82-I	2	11,599	$449,625	$439,402	($10,223)	-2.3%
DEMAND LEVEL II (TOD)	82-II	1	9,614	401,160	398,474	(2,685)	-0.7%
GENERAL PRIMARY VOLTAGE							
DEMAND LEVEL I	83-I	66	336,557	15,486,028	15,615,117	129,089	0.8%
DEMAND LEVEL II (TOD)	83-II	107	3,410,621	153,257,704	153,804,371	546,666	0.4%
TOTAL 82 & 83		176	3,768,392	$169,594,517	$170,257,363	$662,846	0.4%
LARGE INDUSTRIAL (TOD):							
TRANSMISSION VOLTAGE	89	2	454,521	$18,969,221	$18,329,688	($639,532)	-3.4%
STREETLIGHTING:							
STREET AND HIGHWAY LIGHTING	91	547	158,501	$21,541,539	$20,994,646	($546,893)	-2.5%
TRAFFIC SIGNALS	92	96	34,719	1,752,945	1,854,324	101,379	5.8%
RECREATIONAL FIELD LIGHTING	93	34	1,150	103,271	109,237	5,966	5.8%
REVENUE CLASS TOTAL		677	194,370	$23,397,756	$22,958,206	($439,549)	-1.9%
CONTRACTUAL SALES	99	5	3,681,231	$118,114,836	$124,591,266	$6,476,431	5.5%
REVENUE ADJUSTMENTS	-	-	(6,833)	($828,000)	($828,000)		
EMPLOYEE DISCOUNT	-	-	-	(1,135,889)	(1,186,128)		
TOTAL (CYCLE YEAR BASIS)		648,317	34,424,889	$1,720,493,875	$1,807,224,658	$86,730,783	5.0%
CONVERSION ADJ. - CYCLE TO CALENDAR YEAR			36,908	1,762,506	1,740,965		
TOTAL ULTIMATE SALES (CALENDAR YEAR BASIS)			34,461,797	$1,722,256,381	$1,808,965,623	$86,709,242	5.0%

95-322

Percent of Marginal Costs
Based on 1995/1996 Loads and Costs
Base Revenues w/o Adjustment Clauses

		Marginal Costs		Present Revenue			Indexed(1)	Proposed Revenue			Indexed(1)
						% of	% of			% of	% of
	Loads (a)	($000) (b)	mills/kWh (c)	($000) (d)	mills/kWh (e)	Marg Cost (f)=(e)/(c)	Marg Cost (g)	($000) (h)	mills/kWh (i)	Marg Cost (j)=(i)/(c)	Marg Cost (k)
Residential	13,811,054	$1,175,680	85.13	$809,727	58.63	68.9%	91.7%	$882,205	63.88	75.0%	94.4%
Small Commercial	2,358,215	$196,105	83.16	$146,186	61.99	74.5%	99.2%	$154,810	65.65	78.9%	99.4%
Medium Commercial/ Industrial (2)	8,547,808	$529,544	61.95	$421,235	49.28	79.5%	105.9%	$434,961	50.89	82.1%	103.4%
Large Commercial/ Industrial (3)	5,521,703	$279,044	50.54	$249,557	45.20	89.4%	119.1%	$250,843	45.43	89.9%	113.1%
Optional Time-of-Day	121,701	$7,192	59.10	$6,736	55.35	93.7%	124.7%	$6,886	56.58	95.7%	120.5%
Irrigation & Drainage Pumping Service	153,947	$19,342	125.64	$7,124	46.28	36.8%	49.0%	$7,761	50.42	40.1%	50.5%
Lighting (4) (Energy Charges Only)	233,389	$13,974	59.87	$12,606	54.01	90.2%	120.1%	$13,331	57.12	95.4%	120.1%
Grand Total (5)	30,780,566	$2,221,244	72.16	$1,668,627	54.21	75.1%	100.0%	$1,764,970	57.34	79.5%	100.0%

Notes:

(1) To index, each classes' percent of marginal costs was multiplied by the ratio of total marginal costs to total present/proposed revenue.
(2) Sch 31/32 II, Sch 82/83 I
(3) Sch 31/32 III, Sch 82/83 II, and Sch 89
(4) Sch 14, 15, 91, and 92
(5) Includes misc. schedules, adjustments to revenue, and fixed streetlight costs.

95-322

ENCLOSURE II TO VPN-002-2005

OPUC ORDER NO. 01-777, ENTERED AUGUST 31, 2001, IN DOCKET UE 115

ORDER NO. 01-777

ENTERED AUG 31 2001

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149.	)	ORDER

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

APPENDICES

ORDER NO. 01-777

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149.	)	ORDER

SUMMARY

In this order, the Commission approves new rate schedules for Portland General Electric Company (PGE). The new schedules reflect the unprecedented increases in the prices for electricity on the wholesale power markets. Due to a combination of increased demand, lack of new generating facilities, low water conditions, and the troubled deregulation effort in California, wholesale electricity prices have nearly tripled since PGE's last general rate change in late 1997. At that time, power costs averaged 1.37 cents/kilowatt-hour (kWh). Power costs have since increased some 173 percent, and now average 3.74 cents/kWh. The power markets have also become extremely volatile, with peak power prices exceeding $1.20/kWh at various times last winter.

The new schedules also restructure and reprice PGE's services, beginning March 1, 2002, to meet the requirements of Senate Bill 1149, an electric industry restructuring bill.[1] SB 1149 requires electric utilities to functionally separate their power generation from distribution services and provide consumers with access to power supply options.

The exact impact on customer rates will not be known until September 12, 2001, the date that energy rates will be calculated based on PGE's forward price curves and the value of the company's resources. Based on PGE's latest power cost calculations and the terms of this order, however, the Commission projects an overall rate increase in customer rates of approximately 35 percent. Applying this estimate to the rate spread adopted for the new schedules, residential rates will increase about 26 percent, and industrial rates will increase about 46 percent. In its September 12, 2001 filing, PGE will submit a rate design table identifying, for each rate schedule, the specific percentage increase resulting from the updated power cost estimates and consistent with the terms of this order.

In an effort to help offset rising power costs, the Commission imposes reductions to PGE's non-power Operation and Management (O&M) budget. Given the largely unavoidable power cost increases and the resulting impact on customer rates, the Commission concludes that it is prudent for PGE to reduce other discretionary internal operating costs. With the decisions in

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[1] In House Bill 3633, the 2001 Legislative Assembly delayed the implementation of SB 1149 from October 1, 2001 to March 1, 2002.

this order adopting stipulations among the parties and resolving contested issues, the authorized increase, aside from the effect of power costs, is almost $50 million less than the company requested.

In addition, the Commission adopts a Power Cost Adjustment (PCA) mechanism that will lower rates if the company's power costs decline. The PCA establishes how PGE will account for variations between expected power costs included in base rates and actual power costs, and describes the method by which the company and its customers will share in the benefits and burdens of such variations. This mechanism will track the fluctuations in power costs and require a refund to customers of overcollections exceeding a preset amount. The PCA balances the interests of customers and PGE and helps ensure the company's continued ability to secure a reliable source of energy to meet demand.

The Commission also adopts a tiered rate structure for residential customers that will benefit consumers who use lower amounts of energy. The first 225 kWh of electricity used is priced lower than electricity used above and beyond that amount. The rate design also ensures that residential and small farm customers receive the full benefit of low-cost subscription power managed by the Bonneville Power Administration (BPA).

INTRODUCTION

On October 2, 2000, Portland General Electric (PGE) filed Advice No. 00-14, an application for revised tariff schedules. The tariffs were designed to implement a general rate revision and put into operation the provisions of Senate Bill 1149.[2] Among other things, PGE's filing unbundled the company's services into generation, transmission, distribution, ancillary, and customer services, established charges to electricity service suppliers, formulated market-priced standard offers, and calculated competitive transition amounts.

At its October 20, 2000 Public Meeting, the Commission found good cause to investigate the filing and suspended Advice No. 00-14 pursuant to ORS 757.215. Because the Commission determined that the rate investigation could not be completed within an initial six-month suspension period, it ordered that the filing be suspended for a total period of nine months from November 1, 2000.[3] PGE later waived the statutory suspension period and agreed to an extension of the suspension through August 31, 2001, with rates to become effective October 1, 2001.[4]

Prehearing Conference

On October 24, 2000, Michael Grant, an Administrative Law Judge (ALJ), held a prehearing conference to identify parties and to establish a procedural schedule. The following participated as parties to this proceeding: PGE, Industrial Customers of Northwest Utilities

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[2] PGE's filing originally included the company's proposal to reclassify its transmission assets. That proposal, however, was later bifurcated to allow timely review by the Federal Energy Regulatory Commission (FERC). On March 14, 2001, PGE, Oregon Office of Energy, and Staff filed a stipulation intended to resolve all issues related to reclassification of transmission assets. No party opposed the stipulation, which was also signed by Fred Meyer Stores. We reviewed the stipulation and adopted it in Order No. 01-325.

[3] Order No. 00-669.

[4] Orders No. 01- 575 and 01-724.

(ICNU), the Citizens' Utility Board (CUB), Fred Meyer Stores (Fred Meyer), City of Portland (Portland), League of Oregon Cities (League), Oregon Office of Energy (OOE), Oregon Steel Mills, Inc. (OSM), City of Glendale (Glendale), PG&E National Energy Group, Inc., Northwest Natural Gas Company, Associated Oregon Industries, PacifiCorp, Northwest Energy Coalition, Renewable Northwest Project, ATOFINA Chemicals, Portland BOMA, Warren Parrish, and the Commission Staff (Staff).

Public Hearings and Presentations

In November and December 2000, the Commission held public comment hearings in Portland and Salem to give the general public an opportunity to comment on PGE's tariff filings. In addition, the Commission held special public meetings for opening and closing presentations by the parties. In March 2001, the Commission heard opening presentations from PGE, PacifiCorp, ICNU, CUB, City of Portland, Fred Meyer Stores, and Staff. In July 2001, the Commission heard closing oral argument from PGE, ICNU, CUB, Fred Meyer, OSM, OOE, and Staff.

Commission Orders

During the course of this proceeding, the Commission issued three orders relating to procedural matters. On December 4, 2000, the Commission issued Order No. 00-765, granting PGE additional protection for confidential information.

On March 21, 2001, the Commission issued Order No. 01-249, denying ICNU's request to allow a former Staff employee, John Thornton, to participate as an expert witness. The Commission, in explaining OAR 860-012-0010(2), set forth an analysis for determining when a former employee may testify for another party. In this case, the Commission determined that Mr. Thornton could not appear as an expert witness in this docket or in docket UE 116, the PacifiCorp restructuring and rate case.

On July 20, 2001, the Commission issued Order No. 01-592, which involved a question certified to the Commission by the presiding ALJs in dockets UE 115 and UE 116. In that order, PGE and PacifiCorp had challenged the agency's Internal Operating Guidelines that govern post-hearing procedures. They claimed that the policies were unlawful and sought the immediate adoption of more stringent procedures recommended in the Report to the Oregon Legislature from the HB 3615 Interim Task Force (Task Force).

The Commission determined that the Internal Operating Guidelines, which allow limited post-hearing communications between Commissioners and so-called "party Staff," were legal. The Commission, however, acknowledged the utilities' concerns about Staff's role in the decision-making process, and noted that the issue will be carefully examined during review of the Task Force Report. Therefore, the Commission concluded that, while the Task Force recommendations should not be fully implemented at this time, Staff witnesses who sponsored testimony or testified at hearing would not appear at decision meetings, and that only "non-party" Staff members would participate in deliberations on rate of return issues.

Evidentiary Hearings

On June 4 and 5, 2001, ALJ Grant held evidentiary hearings in Salem, Oregon. During those proceedings, the following appearances were entered: J. Jeffery Dudley, and Philip Van Der Weele, attorneys, appeared on behalf of PGE; David Hatton, Assistant Attorney General, appeared on behalf of Staff.

Based on the record in these proceedings, we make the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Applicable Law

In this rate case, the Commission's function involves two primary steps. First, we must determine how much revenue PGE is entitled to receive. A utility's revenue requirement is determined on the basis of the utility's costs.[5] Second, we must allocate the revenue requirement among the utility's customer classes.

In the revenue requirement phase of a rate case, we must determine: (1) the gross utility revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which a return should be earned; and (4) the rate of return to be applied to the rate base to establish the return to which the stockholders of the utility are reasonably entitled.[6] The purpose of answering these questions is to determine the utility's reasonable costs of providing service and expected revenues, so that the Commission can set utility rates at just and reasonable levels.

A question has arisen in this case regarding the application of the burden of proof. The phrase "burden of proof" has two meanings: one to refer to a party's burden of producing evidence; the other to a party's obligation to establish a given proposition in order to succeed.[7] To distinguish these two meanings, we refer to the burden of production and the burden of persuasion.[8] In Commission proceedings, ORS 757.210 provides that a "utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable." This burden is borne by the utility throughout the proceeding and does not shift to any other party.

PGE acknowledges that the utility has the initial burden of production and persuasion to show that the proposed rates are just and reasonable. PGE contends, however, that once the utility presents its evidence, both burdens shift to parties opposing the rate increase.[9] It relies on the Commission's decision in docket UT 125, *In re U S WEST Communication, Inc.*, which provides, in pertinent part:

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[5] *See, e.g., American Can Co. v. Lobdell*, 55 Or App 451, 454-55, *rev den* 293 Or 190 (1982).

[6] *See Pacific Northwest Bell Tel. Co. v. Sabin*, 21 Or App 200, 205 n. 4, *rev den* (1975).

[7] *See Hansen v. Oregon-Wash. R. & Nav. Co.*, 97 Or 190 (1920).

[8] *See, e.g.*, Oregon Evidence Code, Rule 305 and Rule 307.

[9] We note that PGE's claim is contrary to the argument traditionally raised by utilities when scheduling the filing of testimony and order of appearance at hearing. In rate cases, the utilities have always insisted on having the last word due to its burden to show that the proposed rates are just and reasonable.

> "[U S WEST] as the proponent of the rate increase must submit evidence showing that its proposed rates are just and reasonable. Once [U S WEST] has presented its evidence, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Staff or an intervenor, if it opposes the utility's claimed costs, must in turn show that the costs are not reasonable. Each time the burden of going forward shifts, the burden of persuasion shifts as well. That is, each party who has the burden of going forward must, in order to prevail, persuade us by competent evidence that its position with respect to that set of costs should prevail."[10]

PGE's reliance on the above-cited language is misplaced. First, PGE ignores the Commission's concluding paragraph to that section, where it clarified that:

> "The Commission's role is to weigh the evidence presented on each issue in the case and determine where the preponderance lies. We make that decision on the record as a whole. The basic decision we make with respect to each issue in this case is whether the utility has produced persuasive evidence that its revenue requirement is reasonable. A component of that decision is whether Staff has persuasively rebutted [U S WEST's] revenue requirement evidence. *We reject [U S WEST's] arguments that Staff has the 'burden of proof' with respect to disallowances and test year adjustments, because the arguments distort the way evidence is presented and decisions are made in a rate case.*"[11]

When the section is read in its entirety, it is clear that the Commission did not agree with U S WEST's arguments about shifting burdens. More importantly, however, the Commission later rescinded Order No. 97-171, and did not readopt the language relied upon by PGE in Order No. 00-191.[12] Thus, that section has been withdrawn and no longer has precedential value.

In our most recent rate case, docket UG 132, *In re Northwest Natural Gas Company*, we stated:

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[10] Order No. 97-171 at 8.

[11] *Id.* at 8. (Emphasis added.)

[12] We note that Order No. 00-191 contained a general reference to the burden of proof language relied upon by PGE. Specifically, the order states at page 15:

> "As we stated above, in the section called [U S WEST's] Burden of Proof Argument, [U S WEST] must show that its expenses are reasonable for us to allow them as part of the revenue requirement calculation."

Although Order No. 00-191 contains no section entitled "[U S WEST's] Burden of Proof Argument," PGE claims that the inclusion of this reference indicates that the Commission implicitly adopted the burden of proof language. PGE is mistaken. We simply made an error by placing a reference to a section in Order No. 00-191 that does not exist.

> "As the petitioner in this rate case, NW Natural has the burden of proof on all issues. Thus, NW Natural must submit evidence showing that its proposed rates are just and reasonable. Once the company has presented its evidence, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Staff or an intervenor, if it opposes the utility's claim costs, may in turn show that the costs are not reasonable."[13]

We adhere to that language and affirm that, under ORS 757.210, the burden of showing that the proposed rate is just and reasonable is borne by the utility throughout the proceeding. Thus, if PGE makes a proposed change that is disputed by another party, PGE still has the burden to show, by a preponderance of evidence, that the change is just and reasonable. If it fails to meet that burden, either because the opposing party presented compelling evidence in opposition to the proposal, or because PGE failed to present compelling information in the first place, then PGE does not prevail.

STIPULATED ISSUES

PGE entered into five stipulations designed to resolve many of the contested issues in this proceeding. On April 26, 2001, PGE, Staff and Fred Meyer filed a stipulation regarding changes to PGE's cost of service. The stipulation represents a settlement of all revenue requirement issues identified by Staff except the authorized return on equity portion of the cost of capital and net variable power costs. Several non-revenue requirement issues are also covered by the stipulation. The stipulation, which is attached as Appendix B, is supported by joint testimony of Jim Barnes and Sara Cardwell of PGE, and Ed Krantz of Staff.

On June 7, 2001, PGE, Portland, and League submitted a stipulation intended to resolve specific rate and tariff issues identified by Portland and League in their opening testimony. These issues include interconnection standards, restoration of utility services, utility relocation, allocation of ancillary service costs, and streetlights. The stipulation, which is attached as Appendix C, is supported by joint testimony of Sara Cardwell of PGE, David Tooze, Duane Sanger, and Bill Graham of Portland, and Andrea Fogue of League.

On July 27, 2001, PGE, Staff, ICNU, CUB, and Fred Meyer filed a stipulation designed to resolve all power cost issues. Most notably, the stipulation establishes a mechanism by which PGE will value its long-term and short-term resources for the purposes of establishing rates for energy services. It also establishes a mechanism by which PGE will account for variations between expected power costs included in base rates and actual power costs, and the method by which the company and its customers will share in the benefits and burdens of such variations. The stipulation, which is attached as Appendix D, is supported by joint testimony of Stefan Brown of Staff, Bob Jenks of CUB, Lincoln Wolverton of ICNU, Kevin Higgins of Fred Meyer, and Randy Dahlgren of PGE. To help further explain the stipulation, PGE and Staff submitted a letter from PGE counsel that clarifies the assumptions and inputs that the company will use in its final Monet power cost run. The letter, dated August 20, 2001, is included as an additional attachment to the stipulation set forth in Appendix D.

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[13] Order No. 99-697 at 3. (*Statutory language and citation omitted.*)

On August 6, 2001, PGE, Staff, and Fred Meyer filed a supplemental stipulation regarding franchise fees and steam sales. The stipulation adjusts PGE's revenue requirement to reflect the company's agreement to permit cities the ability to choose between the volumetric or revenue-based method of calculating franchise fees. The stipulation also adjusts steam sales to incorporate a recent contract to sell steam at PGE's Coyote Springs Generating Plant (Coyote Plant). The stipulation, attached as Appendix E, is supported by an explanatory brief.

Finally, on August 10, 2001, PGE and Staff filed a stipulation concerning residential rate design for Schedule 7. The stipulation is intended to resolve how the benefits and burdens of subscription power from the Bonneville Power Administration (BPA), as well as cash benefits, should be flowed through to eligible customers, and how the Resource Value Mechanism in PGE's Schedule 125 should be applied to residential and small farm classes of customers. The stipulation is attached as Appendix F and supported by an explanatory brief.

All five stipulations and supporting testimony were entered into the record of this proceeding as evidence pursuant to OAR 860-014-0085(1). We address each separately.

I. Revenue Requirement Stipulation

PGE, Fred Meyer, and Staff filed a stipulation that represents a settlement of most of the revenue requirement issues raised by Staff. The parties' settlement results in a $135.6 million reduction in rate base, a $40.6 million reduction in operating expenses, and an increase in other revenue of $1.7 million from PGE's original proposal. The stipulating parties believe that each of the adjustments discussed in the stipulation are reasonable and, overall, will yield fair and reasonable rates if adopted by the Commission.

CUB and ICNU are not parties to the stipulation and believe that PGE's non-power O&M costs are inflated. PGE initially sought $229.3 million in non-power O&M costs. The stipulation reduces PGE's request to $206.9 million. CUB and ICNU contend that this stipulated amount is excessive and should be further reduced. To demonstrate the significant increase in these costs, ICNU claims that PGE's regulatory adjusted average cost per customer averaged $219 during 1997-1999. Even with the adjustments contained in the stipulation, ICNU calculates that this figure increases to $275 per customer for 2002, a 25 percent increase.

Preliminarily, CUB and ICNU question whether PGE may have inflated its non-power O&M costs to account for the six-year rate freeze contained in the PGE/Sierra Pacific merger stipulation. This potential rate freeze, CUB and ICNU maintain, appears to have caused the company to inflate its costs in this docket to account for future increases in program costs occurring over the next six-year period.

CUB and ICNU are particularly troubled by the proposed increase in PGE's non-power O&M costs given the significant and largely unavoidable increases in power costs. The parties believe it is inappropriate for PGE to initiate, at this time, large and expensive increases in any portions of its regulated business. Before passing these additional expenses on to ratepayers, CUB and ICNU contend that the Commission should first consider the rate impact on customers and determine whether some non-power expenditures should be delayed or simply not made at this time. CUB notes that the Commission has previously ordered utilities to reduce discretionary costs to mitigate a significant rate increase.[14]

To offset the rising power costs, CUB and ICNU recommend that PGE's non-power O&M costs be limited to the rate of inflation. They each present similar, but slightly differing inflation-escalator models to forecast a reasonable level of expenditures. Adjusting the company's 1999 actual costs for inflation, CUB contends that PGE's 2002 test-year forecast for non-energy expenditures, as originally filed, should be reduced by $61.9 million. CUB proposes the Commission achieve this inflation-based target by accepting some elements of the stipulation and making additional reductions for customer service, labor, distribution O&M, technology, and other revenues. These adjustments, which are further addressed below, reduce PGE's non-power O&M costs by $55 million.

ICNU proposes an alternative test year forecast by taking PGE's 1999 actual non-power O&M expenses, applying the regulatory adjustments from docket UE 88, and escalating the results by anticipated customer growth and inflation. This methodology results in base 2002 test year non-power O&M costs of $175.6 million, a $31.3 million reduction from the stipulation. If the Commission does not adopt this alternative test year forecast, ICNU proposes the Commission make specific adjustments in addition to those contained in the stipulation. These adjustments are also addressed below.

In response, PGE contends that the non-power O&M costs contained in the stipulation are reasonable. It objects to CUB's and ICNU's speculation that the company inflated the 2002 test year forecast in anticipation of the potential six-year rate freeze resulting from the PGE-Sierra Pacific merger. PGE explains that it developed its forecasted revenue requirement using traditional ratemaking principles. It started with budget information and adjusted the numbers to remove abnormalities and to include recurring expenses and revenues that were reasonably certain to occur during the 2002 test year.

Next, PGE objects to CUB's and ICNU's inflation-escalator proposals to establish non-power O&M costs. PGE contends that the approach violates established ratemaking principles. Citing *American Can Co. v. Lobdell*, and *In re Pacific Northwest Bell Co.*, PGE argues that a utility's forecast for the test year must consider known and measurable changes that are expected to persist.[15] PGE points out that, under CUB's and ICNU's proposal, the Commission would ignore numerous factors that relate to the company's operating costs and expenditures. Moreover, PGE contends that CUB and ICNU are essentially asking for a

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[14] *See In re Portland General Electric Company*, Order No. 95-322.

[15] *See* footnotes 5 and 6. In *American Can*, the Supreme Court explained that:

> "When an historic test year is used, adjustment to the test year data are made to remove abnormal events not expected to persist into the future. When a future test year is used, the data is drawn from budget figures and financial models of the utility. *Abnormal events of the past are therefore excluded and all know future changes are included.*" (Emphasis added.)

moratorium on all spending that exceeds inflation—without regard to the company's need to make appropriate up-front capital investments and properly maintain its plant. PGE believes that, in the long run, the adoption of a management-by-crisis approach would increase overall costs. Due to these limitations, PGE contends that the inflation-escalator approach cannot establish reasonable expenditures and should be rejected by the Commission.

Before turning to CUB's and ICNU's specific adjustments to PGE's non-power O&M costs, we first find no evidence that the six-year rate freeze adopted in the PGE-Sierra Pacific merger case influenced either PGE's 2002 test year or the revenue requirement stipulation between PGE, Staff, and Fred Meyer. Neither CUB nor ICNU provide any support for their allegation. Moreover, the record contradicts their claim. PGE had completed the underlying budget process before the parties developed the six-year rate freeze in the merger docket, and actually made its rate filing in this case before the Commission approved the merger agreement. In addition, PGE took specific steps to ensure that consideration of a six-year rate freeze did not affect the budget process. For these reasons, we conclude that PGE, Staff and Fred Meyer used a 2002 test year without considering the impact of the Sierra Pacific acquisition.

We also reject CUB's and ICNU's inflation-escalator proposals as independent methods to establish non-power O&M costs for PGE. Consistent with established Oregon ratemaking principles, PGE's test year should be based on actual or budgeted expenditures and adjusted to remove abnormalities and to include known and measurable changes that are expected to persist.[16] The parties' respective inflation benchmark proposals are not appropriate for evaluating PGE's expenditures, because the methodologies do not examine the reasonableness of historical operations, fail to consider abnormalities in the baseline year's results of operations, and do not take into account known and measurable changes between the baseline and test year, such as the passage of SB 1149.

We further conclude, however, that CUB's and ICNU's inflation-benchmark comparisons, as well as ICNU's cost per customer assessment, highlight the increases that PGE is seeking for its non-power O&M costs. While PGE disputes the accuracy of these comparisons and recommends numerous corrections, the fact remains that PGE's stipulated non-power O&M costs are significantly higher than the company's actual costs in 1999. We acknowledge that the implementation of SB 1149 drives many of these cost increases. Nonetheless, given the unavoidable increases in power costs and resulting impact on customer rates, it is imperative that we carefully review the company's internal operating costs and capital expenditures to ensure that proposed increases are reasonable and prudent. With this in mind, we turn to the specific non-power O&M adjustments proposed by CUB and ICNU. We address each parties' recommendations separately.

CUB Recommendations

CUB recommends that the Commission reduce PGE's non-power O&M costs, as originally filed, by $55 million. CUB proposes the Commission achieve this result by accepting

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[16] *See, e.g., In re U S WEST Communications*, Order No. 00-191; *In re PacifiCorp*, Order No. 00-091; *In re Pacific Northwest Bell*, Order No. 87-406.

some elements of the stipulation[17] and making additional reductions for customer service, labor, distribution O&M, technology, and other revenues. The individual adjustments are summarized as follows:

1. Customer Service

CUB contends that PGE's proposed revenue requirement for customer service of $54.8 million is simply too great for customers to absorb, given the forecasted increase in power costs. CUB proposes an overall reduction in Customer Service of $13.86 million, which is broken down as follows:

- Reduce PGE's request for $39.2 million to deliver information and service by $11.05 million. CUB believes that the cost of the Web, responding to media requests and initiating channels of information should be split 50-50 between customers and shareholders. In addition, the cost of providing information to customers through telephone and personal contact should be reduced 25 percent.
- Eliminate the $1.2 million cost for PGE's proposed credit card payment option.
- Reduce by two-thirds the cost for Network Meter Reading/Automatic Meter Reading (NMR/AMR) system, as only one-third of the system is for customers located in test areas where the program is necessary to implement SB 1149.
- Eliminate the $750,000 allocation of distributed generation costs to customer service.
- Reduce the cost of customer surveys by $100,000 by increasing the amount allocated to non-regulated operations.
- Eliminate the $160,000 costs for WeatherWise.

In response, PGE contends that—with one minor exception—the record does not support the proposed reductions to customer costs. PGE first claims that CUB provides little

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[17] CUB participated in settlement discussion and agrees with some adjustments set forth in the stipulation. Those adjustments, which reduce non-power O&M costs by $26.53 million, are as follows:

Issue #	Description	Adjustment	Issue #	Description	Adjustment
S-14	SERP	-$4.645 million	S-32	SERP O&M	-$1.250 million
S-15	Remove Trojan	-$16.584 million	S-33	Bonus/Incentive Pay	-$2.477 million
S-16	Remove NEIL	+$3.818 million	S-35	OPUC Wage Formula	-$1.717 million
S-28	Public Purpose Adj.	-$0.699 million	S-38	Y2K Amortization	-$1.977 million
S-31	A&G Accounts	-$1.00 million		Total	-$26.53 million

analysis for its proposed $11.05 million reduction for the delivery of information and services. PGE observes that the company already allocates 62 percent of Internet Web (Web) costs to non-regulated activities—well above the 50 percent CUB claims is reasonable. PGE adds that the company has justified the need for, and the benefit of, a credit card payment option for customers, and that the reduction of the scope of the NMR/AMR system will not save money due to the fixed costs of the system. In addition, PGE explains that a portion of distributed generation is properly allocated to customer service, as certain costs involve program development, testing, and analysis. Similarly, PGE maintains that customer surveys are properly allocated to regulated operations, since less than one percent of the cost, effort, and questions related to customer surveys concern non-regulated services. PGE does agree with CUB's proposed adjustment for WeatherWise, and acknowledges that approximately $160,000 should be removed from above-the-line expenditures for this program.

After our review, we share CUB's concerns about the significant increases to PGE's Customer Service costs. While some of these costs are related to PGE's efforts to meet the requirements of SB 1149, others are in response to PGE's belief that its customers want new services, more options, and better communication channels. To address these perceived needs, PGE is adding payment options, expanding communication choices, adding new customer services, and increasing the frequency of customer surveys. PGE admits that these changes cost more, but explains that they provide more value to PGE's customers.

PGE is correct that we should judge these services and the costs associated with them on the basis of the value they provide and the demand they meet. We must do so, however, in the context of PGE's overall request, which includes significant increases to its power costs. While we commend PGE for it efforts to enhance its services based on customer requests, we question whether its customers would enthusiastically support the addition of costly new programs when also faced with unprecedented power cost increases. Indeed, as CUB's counsel explained during oral argument:

> "[A]dvocates of PGE's customers are here to say that we're not nearly as concerned about more payment options right now as we are about how we're going to pay for the electricity we use. More than anything, customers want to be able to afford to use electricity to heat and light their homes, run appliances and, in short, live their lives. Business customers want to stay in business."[18]

We find that some of PGE's Customer Service expenses, such as the distributed generation, NMR/AMR system costs, and others related to SB 1149, should not be reduced or delayed at this time. PGE has showed that postponing these programs will not lead to decreased costs, and may actually increase costs over time. PGE has failed, however, to establish that it has made every reasonable effort to reduce other, discretionary Customer Service costs to help offset its spiraling power costs. We acknowledge that such reductions require difficult choices. Nonetheless, given the increasing wholesale power costs and PGE's reliance on that market to meet customer load, we believe that PGE must consider the rate impact on customers and critically examine whether some of these proposed expenditures should be delayed or simply not made at this time.

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[18] Oral Argument, July 13, 2001, Transcript at 32, lines 13-19.

For these reasons, we agree that the stipulated Customer Service costs should be further reduced. As ICNU notes, customers want an economical power supply more than a new Internet Website or the ability to pay their bill with a credit card. However, we decline to adopt CUB's overall proposal to reduce Customer Service costs by $13.86 million. As noted above, some challenged costs should not be reduced or delayed at this time. Moreover, CUB has double-counted some costs, such as the credit card payment option, by targeting the same expense in two separate adjustments, and targeted other expenses that are already reduced by the revenue requirement stipulation. Adjusting CUB's proposal, we conclude that PGE's Customer Service costs forecast for the 2002 test year should be reduced by an additional $3.5 million above and beyond the adjustments contained in the stipulation. We decline to identify particular program areas that may be susceptible to reassessment or to impose specific cost reductions. These discretionary costs are best managed by the company.

2. Labor

CUB notes that, as with any large organization, PGE has staffing vacancies at any point in time. Due to these vacancies, CUB claims that PGE's actual employment costs were 5.3 percent below the budgeted employment level. In order to account for these unfilled positions for the 2002 test period, CUB proposes a reduction of 143.2 full-time equivalent (FTE) positions. This results in a reduction of operating expense of $6.4 million.

PGE questions CUB's methodology, but argues that a proper application of the analysis shows that the stipulated reduction of FTEs is reasonable. Using a longer time period (1995 through 2000), PGE calculates the percentage of unfilled positions to be 2.9 percent below budget. Applying this calculation to the 2002 forecast results in a proposed reduction of 78 FTEs, which is two less than the 80 FTEs eliminated by the stipulation.

We agree with PGE and adopt, as reasonable, the stipulated adjustment to the company's labor costs. PGE has demonstrated that CUB's analysis, when applied over the last six years, supports the stipulated reduction of 80 FTEs. Moreover, the 2002 test period, as stipulated, has a slightly lower FTE count than PGE's FTE total as of December 31, 2000. The stipulation, therefore, effectively caps the level of FTEs included in customer rates to the number of FTEs employed at the end of last year.

3. Distribution O&M

CUB contends that PGE's distribution O&M costs should be limited to 1999 actuals, adjusted for inflation. To accomplish this, CUB argues that these costs should be reduced by $3.9 million. PGE counters that CUB's suggestion to delay these expenditures, which are required to ensure safety, reliability, and regulatory compliance, is irresponsible.

We find no basis to adopt CUB's proposed adjustment to PGE's distribution O&M costs. As PGE notes, CUB has failed to question a single program as unnecessary or unreasonable, and does not allege that PGE's forecast of the cost of any program is inaccurate. We have previously rejected an inflation-escalator approach as an independent means for establishing PGE's revenue requirement. Accordingly, in the absence of any specific information challenging PGE's proposed expenditures for these critical services, we are unwilling to cap such costs with a simple inflation factor, as CUB recommends.

4. Technology

CUB believes that PGE's technology costs support non-regulated activities and should be adjusted accordingly. For example, CUB claims that the company's website provides information on a variety of non-regulated activities, such as wholesale power products and Earth Smart Homes. CUB also contends that its customer database has uses that go beyond the regulated system. For these reasons, CUB proposes a 30 percent, or $4.3 million, reduction in PGE's Information Technology (IT) budget.

PGE responds that CUB's proposed 30 percent reduction is unsupported. PGE explains that the challenged website program is just one of 16 different IT systems presented in PGE's case, and adds that it already allocates almost two-thirds of its web budget to non-regulated activities. Moreover, PGE clarifies that its Customer Information System (CIS) is not part of its IT budget, but rather is part of Customer Services and is specifically subject to the stipulation adjustment S-29.

We reject CUB's proposed reduction to PGE's technology costs. Adjustment S-31 of the stipulation, which CUB supports, already reduces the company's IT costs by $1 million. The stipulation also requires an audit of PGE's IT capital expenditures that will result in a refund to customers of capital costs that are not expended or found to be imprudent.[19] Moreover, PGE agrees that its website has non-regulated uses and has allocated almost two-thirds of its costs to non-regulated activities. For these reasons, we accept, as reasonable, the stipulated adjustments relating to PGE's IT costs.

5. Other Revenue

CUB believes that the company's filing underestimates the Other Revenue that it will receive in 2002. CUB claims that PGE's revenues should continue to increase, because of the company's on-going success in increasing revenues from pole attachments. After accepting some adjustments contained in PGE's rebuttal testimony, CUB proposes that Other Revenues be increased to $15.87 million, some $40,000 more than set forth in the stipulation.

PGE responds that CUB's forecast of Other Revenue is overly optimistic. The company believes that CUB's reliance on the growth in pole attachment revenues is misplaced, because the limited number of poles places a limit on any growth in this area. Additionally, PGE notes that many telecommunications companies have recently suspended build-outs of broadband access systems, and that much of the current growth in telecommunications occurs underground.

We reject CUB's proposal to increase PGE's Other Revenue by $40,000. Staff, PGE, and Fred Meyer have stipulated to pole-rental revenues of $5.8 million for 2002, a $100,000 increase from the company's actual revenues in 1999. Given the company's finite number of poles, the suspension of broadband access systems, and expanding use of

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[19] We further address this issue in our analysis of ICNU's proposed adjustments to non-power O&M costs.

underground conduit, we conclude that the projection for Other Revenue contained in the stipulation is reasonable and adopt it.

ICNU Recommendations

Like CUB, ICNU also recommends that the Commission make specific adjustments in addition to those contained in the stipulation. Specifically, ICNU recommends that the Commission: (1) reduce PGE's non-power O&M costs by an additional $13.4 million; (2) adopt certain adjustments proposed by CUB; (3) exclude a portion of PGE's proposed IT costs; and (4) exclude SB 1149 implementation costs. We address each separately.

1. Non-Power O&M Adjustments

ICNU claims that PGE's costs for lobbying, governmental affairs, and strategic planning costs should be excluded from the company's revenue requirement. Citing *Re Cascade Natural Gas Co*, ICNU contends that lobbying and other "expenses for legislative activities should not be borne by ratepayers."[20] These costs include $650,923 for lobbying costs, $510,798 for state, local, and federal governmental affairs, and $1,030,267 for competitive strategic planning, for a total of $2.19 million.

ICNU also contends that PGE has failed to establish that the following new programs and costs increases are warranted and benefit ratepayers: (1) general business support costs ($368,421); (2) administration of compensation programs ($659,717); (3) employee training and development costs ($1,585,831); (4) management of Commission relationship costs ($354,000); and (5) customer service and IT costs ($6,588,577). ICNU states that the removal of these programs results in a total disallowance of approximately $9.5 million.

Finally, ICNU maintains that PGE has included in its test year cost increases related to rates and regulatory affairs that are not reasonably certain to occur in the future. ICNU explains that these costs are related to PGE's filings before state and federal agencies. ICNU does not believe that the year 2000 should be used to gauge a typical level of such activity, and proposes: (1) two adjustments to reduce rates and regulatory affairs costs by a total of $972,697; and (2) two adjustments to reduce legal costs by a total of $691,734. Together, these exclusions result in a $1.66 million reduction.

In response, PGE claims that ICNU has failed to support its specific recommended reductions. First, the company claims that, contrary to ICNU's assertion, the general support and governmental affair cost categories contain no expenses for lobbying. PGE explains that the company always charges lobbying costs below the line. PGE further argues that it has fully justified its costs for general business support, administration of compensation programs, and employee training and development. Moreover, according to the company, historic cost levels and increased regulatory requirements justify the increased expenses for legal services and regulatory affairs.

We agree with a portion of ICNU's proposed adjustments to PGE's non-power O&M costs. PGE adequately rebuts ICNU's allegations relating to governmental affairs and

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[20] Order No. 74-898 at 10.

strategic planning, but fails to sufficiently describe or provide evidence detailing the costs in Ledger N42255, General Support-Manage External Relations. PGE's general assertion that the company "always charges lobbying costs below the line" is not, by itself, a sufficient justification for the expense. Accordingly, we adopt ICNU's proposed $650,923 reduction.

Second, we conclude that PGE has justified its programs and proposed cost increases related to general business support and administration of compensation programs. We agree with ICNU, however, that the company has failed to adequately explain why its proposed employee training and development costs increase from $1.6 million in 1999 to roughly $3.2 million in 2002. PGE explains the various training areas within its Human Resource Department, but offers no explanation as to why its test year training costs are twice those incurred in 1999. Similarly, while PGE identified that $1.3 million of its proposed $1.654 million increase for Commission relationship costs was related to SB 1149 project management, it provided no evidence to justify the remaining $354,000 increase in other, non-SB 1149 costs. Therefore, we adopt ICNU's $1,585,831 reduction in employee and development costs, and exclude $354,000 of PGE's costs associated with management of Commission relationships. We have already reduced PGE's Customer Service costs, pursuant to CUB's recommendations, and decline ICNU's additional request.

With regard to test year cost increases related to rates and regulatory affairs, we agree with ICNU that PGE's 2000 costs should not be considered reflective of typical department activity. As the parties are well aware, the year 2000 started a period of extensive regulatory activity at PGE, primarily due to the passage of SB 1149. Before this Commission alone, PGE initiated this rate case, filed a resource plan in docket UE 118, and actively participated in numerous rulemaking proceedings, such as dockets AR 380 and AR 390. The PGE/Sierra Pacific merger proceeding in docket UM 967 occurred that year. Moreover, the company sought an interim rate increase in docket UE 117, and a power cost adjustment mechanism in dockets UM 1008/1009. We do not believe that it is reasonable to assume that this abnormally high level of regulatory activity will continue to occur in all the future years in which PGE's rates will be in effect. We further agree with PGE, however, that 1999 was a relatively quiet year for the company's regulatory activities. The lack of major contested dockets that year, and the future efforts required for the implementation of SB 1149, confirm that the 2002 test year expenditures should be increased above the level of actual regulatory expenditures for 1999. Accordingly, we adopt half of ICNU's proposed $660,945 adjustment, and reduce PGE's 2002 test year expenditures for rates and regulatory affairs by $330,472. This adjustment allows for a considerable increase in PGE's rates and regulatory affairs budget, yet reflects a reasonable level of future regulatory activity.[21]

We make a similar adjustment to PGE's proposed legal costs in its 2002 test year. PGE has forecasted a $1.0 million increase from 1999 costs based on "the restructuring of PGE's business environment from regulated to competitive."[22] As ICNU notes, however, PGE fails to account for any cost decreases that may be associated with unbundling and the transfer of operational control of transmission assets to a Regional Transmission Organization. Moreover, like the company's regulatory activities, we do not believe that all costs associated with the

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[21] ICNU also recommended an additional $311,752 reduction in rates and regulatory affairs costs, for a total reduction of $972,679. We do not adopt ICNU's additional adjustment, which would reduce expenditures for PGE's Environmental Affairs.

[22] *See* PGE/700, Stevens/7.

competitive transition will continue to occur in all future years. Accordingly, we adopt ICNU's recommendation and disallow half ($505,829) the proposed increase in legal fees. We do not adopt ICNU's additional $185,805 reduction relating to Ledger Account N44013, which includes the cost of Portland General Holdings (PGH) employees performing legal services for PGE.

2. Adopted CUB Adjustments

While the majority of the proposed adjustments by CUB do not impact industrial customers, ICNU accepts, as reasonable, $32.04 million of those adjustments and recommends the Commission adopt them.

We have previously addressed the relevant CUB adjustments above and need not repeat our analysis here.

3. IT Costs

In addition to the adjustments cited above, ICNU recommends the Commission exclude $49 million of PGE's proposed IT costs from the 2002 rate base. ICNU contends that PGE has failed to provide sufficient justification for the need and reasonableness of these costs. PGE responds that ICNU's proposed disallowance for IT costs is unsupported. We agree with PGE.

As clarified above, PGE has the burden of showing that any proposed expense is just and reasonable. Nonetheless, any intervenor opposing a claimed cost must provide competent evidence that such costs are not reasonable. ICNU's proposal, based solely on three lines of testimony, is not sufficient. In fact, ICNU presents no explanation as to whether it objects to the programs or the program's costs.

After a Staff review of the company's new IT systems and their associated capital costs, Staff determined that PGE's capital costs for the new IT systems were prudent and stipulated to full recovery, subject to audit. In this audit, Staff will examine PGE's actual capital expenditures for IT costs, and only those expenditures that are deemed reasonable and prudent will be authorized in rates. Expenditures that are not made or found to be imprudent will be refunded to customers. We conclude that this stipulated agreement on IT costs is reasonable, will ensure that customers will only pay for prudently incurred expenditures, and should be adopted.

4. SB 1149 Costs

ICNU agrees that PGE should be compensated for prudently incurred SB 1149 costs, but contends that PGE has failed to establish that these costs are reasonably certain to occur during the time period when UE 115 rates will be in effect. ICNU notes that PGE's assumption that the restructuring bill will take effect in October 2001 appears to be erroneous, given the recent passage of HB 3633. Moreover, regardless of the implementation date, ICNU believes that the SB 1149 costs are both extraordinary and nonrecurring and should not be included in revenue requirement. ICNU argues that implementation costs not already incurred to date should be recovered through deferred accounting.

In response, PGE first clarifies that HB 3633 delayed implementation of SB 1149 only until March 2002, so SB 1149 will be in effect during 2002. Second, PGE contends that these expenditures reflect new components of PGE's ongoing operations that are required by SB 1149. Thus, PGE argues they are not extraordinary, uncertain, and nonrecurring.

We agree with PGE. The five-month delay of SB 1149 will not materially affect PGE's activities to implement the restructuring. As PGE notes, SB 1149 will take effect in March 2002, and the company will be making expenditures in the first quarter of next year to prepare for the implementation. Contrary to ICNU's assertions, we conclude that the challenged expenditures reflect ordinary, certain, and recurring costs that should be included in PGE's revenue requirement.

Commission Resolution

We appreciate the efforts of PGE, Staff, and Fred Meyer in negotiating and stipulating to 54 separate revenue requirement issues. With the exception of the additional non-power O&M adjustments sought by CUB and ICNU, the stipulation was unopposed by any party. We have reviewed the unopposed portions of the stipulation, find the proposed adjustments contained therein to be reasonable, and conclude that the results should be adopted.

For the reasons cited above, we also find that the results contained in the disputed portions of the stipulation should be adopted, but conclude that additional reductions to PGE's non-power O&M costs are necessary to yield fair and reasonable rates. These adjustments include an additional $3.5 million reduction in Customer Service expenditures and a $3,427,055 reduction in management of Commission and external relationships, employee training and development, rates and regulatory affairs, and legal costs. Moreover, PGE has agreed to CUB's proposed $160,000 reduction for WeatherWise. Together, these additional adjustments total $7,087,055.

II. Portland and League Stipulation

This stipulation covers several issues raised by Portland and League regarding PGE's proposed tariffs, rules, and rates. Under the stipulation, PGE agrees that its interconnection standards will continue to reference applicable Institute of Electrical and Electronics Engineers (IEEE) criteria and that its interconnection standards will follow those IEEE criteria. If Portland or a member of the League opts to pursue interconnection with PGE's distribution or transmission system, PGE will work cooperatively with that municipality in applying these standards. Moreover, PGE agrees to revise Rule C relating to restoration of utility services to confirm that it will reconnect critical retail load consumers as soon as possible. PGE also agrees to continue to work cooperatively with municipalities and other public bodies to identify critical load customers. In addition, PGE agrees to further revise Rule C to clarify what constitutes a "public works project."

The stipulation also addresses disputed issues related to street lighting. The stipulation addresses four rate-related components: (1) circuit charges (marginal costs of service drops); (2) group relamping; (3) power door luminaries; and (4) emergency pole replacements. PGE, Portland, and League request that the Commission approve the various tariff adjustment described in the stipulation. No other party has filed any objection to the stipulation.

Commission Resolution

We have reviewed the Portland and League stipulation and find the proposed adjustments contained therein to be reasonable. Accordingly, the stipulation, set forth in Appendix C, is adopted.

III. Power Cost Stipulation

In this stipulation, PGE, ICNU, CUB, Fred Meyer, and Staff agree on matters related to power costs issues raised in this docket. The stipulation establishes methodologies or mechanisms by which PGE will: (1) establish its power costs; (2) value its long-term and short-term resources and credit that value to all consumers, including consumers selecting direct access; (3) pass all of the benefits of BPA subscription power to all residential and small farm customers; (4) reflect, in rates, the current adverse hydro conditions facing the company; and (5) share, with its customers, the benefits and burdens of variations between expected power costs included in base rates and actual power costs. The stipulation also includes a shopping credit for commercial customers and addresses charges to Boise Cascade.

Under the stipulation, charges for PGE's energy services are based on a combination of market prices and the value of PGE's resources. PGE will first determine the market price of power using its most recent forward price curves. The company will make that determination on September 12, 2001 for this upcoming year, and on November 15 for each calendar year thereafter.[23] In addition to this market price, PGE will credit or charge each customer with the positive or negative value of PGE's resources. This credit or charge will be calculated from the Resource Valuation Mechanism (RVM) set forth in Schedule 125.

The RVM compares, by customer class, the total cost of power from PGE's long-term and short-term resources to the market price of an equivalent amount of power. If total cost of power from either long-term or short-term resources is less (greater) than the market price of an equivalent amount of power, the difference will be provided as a credit (charge) to customers and spread among customers in the class on an equal cents per kWh basis. PGE will make a similar calculation for BPA subscription power to ensure that 100 percent of the benefits of subscription power will flow to eligible customers.[24]

For purposes of allocating total fixed and variable power costs among customer classes and calculating the RVM, PGE will allocate its long-term and short-term resources as follows:

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[23] The stipulation originally listed September 11, 2001 at the valuation date for the upcoming year. In post-stipulation settlement discussions, however, the parties agreed that September 12, 2001 will be the date for final pricing in this docket.

[24] To reflect the projected difference in net variable power costs between expected and normal hydro conditions, PGE will calculate a separate charge under Part C of Schedule 125. This charge is described in Paragraphs 1 and 2 of the Stipulation and is designed to account for the current adverse hydro conditions. The charge applies only until December 31, 2002. The charge is based on reduced hydro generation of 300,000 MWh over the period October 1, 2001 through December 31, 2002, spread to months based on Exhibit E to the stipulation.

(a) First, PGE will allocate its long-term resources among customer classes in proportion to their respective percentages of retail load for the 12 month period ended September 30, 2001;

(b) Second, BPA subscription power will be allocated to the residential and small-farm customers of PGE eligible to participate in BPA's residential exchange program;

(c) Third, PGE will allocate its short-term resources among all customer classes until each customer class has been allocated a sufficient amount of resources to cover the expected load of that class. If resources are insufficient to serve all expected customer load, PGE shall allocate the shortfall among the customer classes in proportion to their respective percentages of expected shortfall. Any shortfall of resources for any customer class shall be filled by market purchases;

(d) Any excess of short-term resources over expected load shall be allocated among all customer classes in proportion to their respective percentages of expected load; and

(e) If, after applying (a) and (b) above, the residential class has sufficient resources to meet expected load, short-term resources shall be allocated to the other classes on a pro rata basis until they reach the same relative position as the residential class. Any remaining short-term resources shall then be allocated in accordance with (d) above.

PGE will next allocate the net variable power costs produced by Monet, its power cost model, for the rate period for long-term resources, short-term resources and BPA subscription power among the customer classes in accordance with their relative percentages of each type of resource. PGE will then allocate and add the fixed costs of long-term resources among the customer classes in accordance with their relative percentages of long-term resources.

The stipulation also adopts a Power Cost Adjustment (PCA) to address the uncertainty in forecasting power costs. The PCA, set forth in Schedule 127, starts with net variable power costs as described above, adjusted for specific items.[25] The credits or charges produced by portions of the RVM are combined with net variable power costs to produce a base net variable power cost (NVPC). The power cost variance (PCV) is then calculated. The PCV is the difference between actual and base NVPC less the difference between actual and base energy revenues. Base energy revenues are the energy revenues forecast from existing tariffs and the load forecast used to develop the base NVPC.

The PCV is then compared to a table in Schedule 127 to determine an adjustment amount that will be charged or credited to customers in rates. The table includes a dead band of negative $28 million to positive $28 million in PCV before there is any adjustment amount. The

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[25] Schedule 127 does not apply to BPA Subscription Power.

table also includes percentage sharing of the PCV between PGE and its customers in percentages ranging from 50 percent to 95 percent. This sharing is designed to motivate PGE to manage its power costs prudently, while recognizing the current volatile power markets.

The stipulation also includes a shopping incentive of 0.5 cents per kWh for large nonresidential customers with load less than 1 MWa. This incentive is limited to the first 10 percent of eligible customers that choose direct access, and its cost is recouped from the eligible class. Finally, the stipulation addresses charges to the Boise Cascade St. Helens Plant.

Commission Resolution

As noted above, this stipulation represents a settlement in compromise of the positions of most of the active parties to this docket concerning power costs. The executing parties recognize that PGE's power cost situation is unique, given PGE's exposure to the wholesale energy market and the current uncertainty and volatility of that market. The parties believe that the stipulation produces several benefits for customers that are consistent with the provisions of SB 1149. No party opposed the stipulation.

After our review, we conclude that the stipulation is reasonable. As the executing parties note, the stipulation establishes rates for PGE's energy services based on the market price of energy. This allows customers to know the actual price of energy by sending the appropriate pricing information to the retail market. In addition, the RVM passes the value of PGE's long-term and short-term resources to all of PGE's customers, including those electing direct access and portfolio service. This promotes competition and choice consistent with SB 1149.

The stipulation also provides the methodology to allocate PGE's resources among customer classes. This will more appropriately allocate, to each customer class, the actual cost to provide energy service and resource value to that class and reduce potential cross-subsidies among customer classes. Finally, the stipulation provides a means for PGE to mitigate the adverse impact of current hydro conditions, and implements a PCA that fairly distributes among the customers and PGE the potential benefits and costs resulting from changes in load, resources and the wholesale power market. Accordingly, the stipulation, set forth in Appendix D, the attached Schedules 125 and 127, and the August 20, 2001 letter explaining the assumptions and inputs that PGE will use in the final Monet run, are adopted.

IV. Supplemental Revenue Requirement Stipulation

PGE, Staff, and Fred Meyer filed this stipulation to resolve the treatment of franchise fees and steam sales. In its original filing, PGE believed that ORS 221.450, as modified by SB 1149, required franchise fees to be paid on a volumetric basis, rather than a revenue sensitive basis described in the previous version of the statute. After discussions with the League, however, PGE now agrees that cities will be able to choose the basis that is most advantageous to them pursuant to a specific set of procedures. Because the parties believe that cities will utilize the revenue basis for fees based on revenues collected in 2001, the stipulation permits PGE to revise its revenue requirements to: (1) reflect a $794,000 increase in franchise fees based on 2002 revenues at current rates, and (2) adjust revenue sensitive costs in the test year 2002 to reflect a 2.26 percent rate.

The steam sale adjustment is due to a recent contract to sell steam produced at PGE's Coyote Plant. Under this stipulation, PGE will decrease Other Revenue by $306,000 to remove imputed steam sales as originally filed. Other Revenue is increased by $1,143,000 to reflect PGE's total estimated steam sales revenue for 2002. Further, PGE will make certain adjustments to its Monet power cost model to reflect expected steam sales for each month. PGE, Staff, and Fred Meyer request the Commission to approve the stipulation. No party opposes it.

Commission Resolution

We have reviewed the supplemental revenue requirement stipulation and find the proposed adjustments contained therein to be reasonable. Accordingly, the stipulation, set forth in Appendix E, is adopted.

V. Rate Design Stipulation

Under the Northwest Regional Power Act, residential and small farm customers of PGE are entitled to share in the benefits of the low cost power sold by the BPA. Traditionally, the BPA provided those benefits in cash to PGE, which in turn has credited its customers under Schedule 102. Beginning in October 2001, however, the BPA will begin providing the benefits in the form of both power and cash. This stipulation is intended to resolve how PGE should pass the BPA power and financial benefits to PGE's residential and small farm customers.

Under the stipulation, PGE will value the BPA subscription power by comparing the cost and market value of that power. This value will flow through to customers under Schedule 102 as a credit or charge per kWh, which will be valued consistently with the way PGE prices energy and establishes the RVM under Schedule 125. This gives customers a credit or charge equal to the rate BPA charges PGE for subscription power, and ensures that all of the benefits and burdens of subscription power will flow through to eligible customers. PGE will also pass through the cash benefits in the form of a credit to all residential customers for all kWhs of use in excess of 225 kWh per month.

PGE and Staff designed the application of the BPA credit, BPA cash and the RVM credit or charge to produce an initial rate differential of between 10 and 25 mills per kWh for residential customers between the first 225 kWh of use per month and any kWh of use in excess of 225 kWh per month. Because changes in the forward price curves applied to PGE's final Monet run may produce a rate differential outside these parameters, the stipulation allows an adjustment to the rate differential so that there is an initial price differential that is neither too large nor too small.

In the stipulation, PGE and Staff also agree that the basic or customer charge shall be $10 per customer per month. Although PGE had originally requested a $7 per month charge, the company provided evidence that customer-related costs are in excess of $15 per month. According to the explanatory brief, Staff and PGE believe that the stipulated rate of $10 per month more accurately reflects the per-customer costs incurred by PGE. PGE and Staff request the Commission to approve the stipulation.

CUB and OOE are not parties to the stipulation, and object to certain portions of it. CUB does not oppose the content of the stipulation, but believes that the explanatory brief supporting the stipulation mischaracterizes the reason why the parties negotiated an increase in the basic or customer charge. While it does not support the proposed increase to $10 per month, it recognizes that the increase avoids the perverse result of having some low use customer rates go down, while overall rates go up. CUB claims that this is the basis for the stipulated increase, not the one contained in the explanatory brief. CUB believes that adoption of the stipulation based on the need to "more accurately reflect the per customer costs incurred by PGE" represents a significant change to Commission policy that is not supported by the record.

OOE also does not oppose PGE's and Staff's settlement on residential rate design. OOE contends, however, that the proposed stipulation does not provide adequate inversion to residential rates to move the rate for use over 1,000 kWh per month significantly closer to the long-run incremental costs for space heat use. Therefore, it recommends the Commission further modify the stipulation by adopting its rate design proposal. Like the stipulated rate design, OOE recommends an initial residential block set at the per-customer amount of BPA power and priced equal to what BPA charges PGE. OOE proposes a second block for use above the BPA block and below 1,000 kWh per month, and a third block, or tail block, for all use above 1,000 kWh.

To move energy charges for space heating closer to the high costs to serve these loads, OOE recommends that the calculation of the average rate for the first 1,000 kWh should equal the sum of the commodity charges, plus the $3.00 increase in the basic rate, divided by 1,000 kWh. It then recommends PGE decrease the net rates for the first 1,000 kWh and increase the net rate for the tail block to obtain a rate differential of 1.1 cents per kWh. OOE explains that this 1.1 cent differential would exist only until further adjustments are applied after October 1, 2001, and that the rate differential could be greater or less than 1.1 cents after that date. OOE claims that the higher tail block rate will begin to provide better price signals for residential customers when making home-heating decisions.

Commission Resolution

We have reviewed the rate design stipulation and find the proposals contained therein to be reasonable. Accordingly, the stipulation, set forth in Appendix F, is adopted. In making this decision, we clarify that we adopt the proposed increase in the basic or customer charge based on reasons cited by CUB. The increase will avoid a rate decrease to low use customers while overall rates are increasing.

We decline to adopt OOE's proposed modification. OOE provides little evidence or analysis of how its proposal would affect consumers or whether it will accomplish its apparent goal of reducing space heating. OOE's proposed rates could significantly affect a large number of customers that live in multi-family dwellings and, consequently, have no control over their heat source. Moreover, it is unclear how many customers that live in single-family dwellings would switch to gas heating under OOE's proposal. Only about 16 percent of PGE's residential customers heat with electricity. Many of these homes have no duct systems, which are necessary for the convenient installation of gas systems.

CONTESTED ISSUES

I. RATE OF RETURN

The United States Supreme Court established the standard for determining cost of capital allowance in utility rate-making proceedings:

> "[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital[.]"[26]

To determine a rate of return on rate base that is appropriate for PGE, we must first identify the costs and components of the company's capital structure. The cost of each capital component is estimated and weighted according to its percentage of total capitalization. These weighted costs of capital are combined to calculate PGE's overall cost of capital, which becomes the allowed rate of return on rate base.

During settlement discussions, PGE and Staff reached agreement on all rate of return issues except PGE's required return on equity (ROE or cost of equity). PGE estimates its required ROE to be 11.5 percent and seeks an authorized ROE at or above that level. PGE contends that this return is the appropriate rate, using a 2002 test year and considering the company's pricing and operation risks. The company's ROE recommendations are based on the joint testimony of Mr. Patrick Hager, PGE's Manager of Regulatory Affairs, and Mr. William Valach, PGE's Manager of Finance (collectively Hager-Valach). Hager-Valach present ROE estimates using a single-stage and multi-stage Discounted Cash Flow (DCF), the Risk Positioning Method, and a comparison of actual determinations of required equity returns in other jurisdictions.[27]

Staff contends that PGE's request is excessive and recommends the adoption of an ROE for the company of 9.0 percent.[28] Staff presents ROE estimates from two witnesses. Bryan Conway (Conway), Staff's Program Manager of Economic and Policy Analysis, presents cost of equity estimates using a single-stage DCF model, the Fisher-Kamin version of the Capital Asset Pricing Model (CAPM), and a qualitative analysis of the Commission's most recent contested ROE decision in docket UG 132.[29] James A. Rothschild (Rothschild), President of Rothschild Financial Consulting, quantifies his cost of equity recommendations using the single-stage and multi-stage DCF model and two versions of what he calls the risk premium/CAPM method.

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[26] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944). We note that the 2001 Legislative Assembly recently codified this standard in HB 3502, amending ORS 756.040(1).

[27] In rebuttal testimony, Hager-Valach update their original ROE recommendations based on information available through April 30, 2001, and make certain adjustments to their DCF analysis based on Staff's testimony. In this order, we address Hager-Valach's recommendations contained in their rebuttal testimony.

[28] Staff originally recommended an authorized ROE of 8.9 percent, but adjusted its recommendation in its opening brief to account for the increase in risk free rate. *See* footnote 35, *infra*.

[29] *In re Northwest Natural Gas Company*, Order No. 99-697.

Our discussion is divided by methodology. For each section, we begin with a review of the methodology, followed by a summary of the parties' recommendations. We then address and resolve the contested issues under each specific methodology. After addressing all five methodologies, we conclude our discussion by adopting an authorized ROE for PGE.

1. Discounted Cash Flow (DCF)

The DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation. The return on equity under the DCF model is the rate that equates the current stock price and expected cash flows to investors.

In this case, the parties used two DCF models. The basic, or single-stage DCF formula assumes a constant growth rate in future dividends. It is generally expressed as:

$$k_e = \frac{D_1}{P_0} + g$$

Where:

k_e = cost of equity;
D_1 = dividends per share over the next 12 months;
P_0 = current stock price; and
g = annual growth rate in future dividends per share.

The multi-stage, or complex DCF formula assumes that growth rates may change over time. That formula is expressed as:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \ldots + \frac{D_n}{(1+k_e)^n}$$

Where:

$D_1 \ldots D_n$ = the expected stream of annual dividends per share.

DCF Estimates

Hager-Valach could not apply the DCF model directly to PGE, because the company is no longer publicly traded following the merger with Enron Corporation. Therefore, as a proxy for PGE, Hager-Valach use three sample groups of electric utility companies. The first group, which they had originally selected in their direct testimony, is comprised of 17 utilities listed in *Moody's* Electric Utility Index and *Standard & Poor's* Electric Utility Index. The second and third sample groups are ones used by Staff in its testimony. Although PGE does not agree with Staff's sample groups, Hager-Valach include them to demonstrate that the different samples did not significantly impact the DCF calculations. Hager-Valach use both the single-stage and multi-stage DCF models.

For their single-stage DCF analysis, Hager-Valach estimate the dividend yield (D_1/P_0) as four times the most recent quarterly dividend payment divided by the stock price.[30] To calculate stock price, Hager-Valach use the month-high closing price, month-low closing price, and the month-end price for each month during the February through April 2001 period.

To determine future growth (g), Hager-Valach use the *br* + *vs* method, which allows for growth through stock issuance and through earnings growth. In this formula, *b* represents the percentage of earnings retained by the company, and *r* represents the rate of return investors expect to earn on the company's book value. For these inputs, Hager-Valach rely on *Value Line*[31] forecasts. For the *vs* component, *v* represents the portion of the proceeds from future stock expected to exceed book value, and *s* is the growth rate of the stock outstanding. For these inputs, Hager-Valach use historical data.

For their multi-stage DCF analysis, Hager-Valach separate dividend growth into three stages. For the first stage, they use *Value Line* forecasts for the indicated dividend for the next 12 months. These forecasts reflect implicit one-year growth rates. Hager-Valach estimate the second growth rate as the annual growth rate occurring between 2001 and 2004. The 2004 dividend is estimated as an average of estimated dividends for the years 2003-2005, as estimated by *Value Line*. For the final growth rate, Hager-Valach use the *br* + *vs* calculations they use in their single-stage DCF.

For the three electric utility sample groups, Hager-Valach's single-stage DCF cost of equity estimates range from 11.44 to 12.80 percent, while their complex DCF estimates range from 10.90 to 12.13 percent.

Staff presents a total of three DCF models: Conway's single-stage model and Rothschild's single-stage and multi-stage models. Conway applies his single-stage DCF analysis to a sample of 42 electric utility companies he believes are suitable for use as a proxy cost of equity estimate for PGE. He limits his sample to companies covered by the *Value Line* Investment Survey that are primarily engaged in retail sales of electricity, companies that have not omitted an annual dividend in the past five years and for whom *Value Line* is forecasting continued dividend payments, and those companies for whom he could calculate CAPM betas.

To compute his yield component, Conway uses reported stock prices for January 11, 2001, and *Value Line* forecasts of dividend per share for each company for the next 12 months. To estimate future growth, Conway uses past dividend growth as an indicator of the marginal investor's expectations of future growth. For his sample of electric companies, Conway examines both the arithmetic and geometric means across the sample of historical dividend growth. Conway's single-stage DCF analysis produces a cost of equity estimate between 7.75 and 8.0 percent.

Rothschild applies his single-stage DCF analysis to four sample groups. First, he examines the groups of electric companies selected by PGE in this proceeding and by PacifiCorp in docket UE 116. Next, to confirm the reasonability of his estimates, he performs a DCF

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[30] Hager-Valach initially used a different methodology, but adopt this approach in response to Staff's testimony. Although Hager-Valach believe that this approach causes the cost of equity to be understated, Hager-Valach adopt it for purposes of this case.

[31] *Value Line* is a widely-circulated subscription service that provides independent analysis of stocks.

analysis on the group of gas distribution companies used by PacifiCorp in docket UE 116, as well as a group of water companies.

Rothschild considers dividend yield data at a recent point in time and over the last year. First, he calculates dividend yield by dividing the most current annualized dividend rate declared by each company by the spot stock price as of February 28, 2001 for each company. He also divides the most current annualized dividend rate declared by the average high and low stock price of each company over the year ended February 28, 2001. He increases the dividend yield result by adding one-half the future expected growth rate so that the yield is equal to an estimate of dividends over the next year.

To calculate a growth rate, Rothschild uses a $br + vs$ formula similar to that used by Hager-Valach, but with different data. He calculates b, the retention rate, based on a derived dividend yield on book value, and r, return on book equity. To determine r, Rothschild examines both analysts' forecasts and historical data for returns on book equity. Finally, he uses *Value Line* forecasts for his vs inputs.

Rothschild's simplified DCF results produce a cost of equity range of 9.17 to 9.24 percent for the PacifiCorp sample group, and a range of 9.47 to 9.71 percent for the PGE sample group. He places no weight, however, on the results for the PGE sample group, which he considers to be an upwardly biased example.

In his multi-stage DCF model, Rothschild separates dividend growth into two stages. His first stage of the model is based on *Value Line's* forecasts for earnings per share and dividends per share for 2000 through 2004. Because *Value Line* does not forecast a specific earnings and dividend projection for every year in that period, Rothschild projects those omitted years by extrapolating the available data.

Rothschild determines second stage earnings by multiplying the future book value per share by the future expected return on book equity used to calculate future growth, g, in his single-stage DCF model. Rothschild projects growth in his second stage for 40 years into the future. Rothschild's complex DCF results produce a cost of equity range of 9.71 to 9.81 percent for PacifiCorp's sample group of electric utility companies.

Disputed DCF Issues

Of the two DCF versions presented, the parties differ the most with regard to the single-stage DCF model. Specifically, the parties disagree significantly on the proper method to calculate the growth component. PGE criticizes Conway's single-stage DCF estimate, because he uses historical data to estimate the growth rate component. While Rothschild uses the same $br + vs$ formula used by Hager-Valach to calculate growth, PGE claims that Rothschild's estimates for retention ratios, b, and return on book equity, r, are highly subjective, downwardly biased, and flawed. Staff counters that Hager-Valach's use of *Value Line* forecasts for retention ratios, b, combined with an historic dividend rate in their calculations, seriously overstates the cost of equity. Staff contends that the mismatch in the time chosen to estimate these two inputs creates substantial and unnecessary error. These differences are so significant that Staff suggests that the Commission simply reject the use of the single-stage version of the DCF model in favor of the multi-stage formula.

Staff and PGE agree that the single-stage version of the DCF model can only be properly used if dividends, earnings, stock price and book value are expected to grow at the same rate. The difficulty arises, however, in selecting the values to use for these inputs. PGE and Staff disagree on whether the use of a forecasted retention ratio requires an adjustment to the current dividend to avoid double counting. Both parties provide a reasonable basis for their respective positions, but neither has sufficiently established why the opposing methodology should be rejected.

We have previously favored use of the multi-stage DCF analysis over the single-stage DCF formula. In docket UG 132, *In re Northwest Natural Gas Company*, we noted that the multi-stage DCF improves on the implicit assumption in the single-stage version that dividends grow indefinitely at the same rate.[32] This limitation of the single-stage DCF model is even more significant given the ongoing restructuring of the electric industry. For this reason, and in light of the parties' significant disagreements over the proper application of the single-stage DCF model, we adopt Staff's recommendation to reject the single-stage DCF analysis in favor of PGE's and Staff's multi-stage DCF results. We conclude that the parties' single-stage DCF analyses provide no information not already contained in their complex DCF analyses. Parties are free to use the single-stage version of the DCF method in future dockets, but they will be expected to show that the required industry stability is present.

Turning to the multi-stage DCF models presented, PGE identifies four primary errors in Rothschild's multi-stage DCF calculation, three of which relate to his second stage growth projections. First, PGE criticizes Rothschild's estimate for expected return on book equity, *r*. PGE notes that, while Rothschild claims to have relied, in part, on *Value Line* forecasts for the companies in PacifiCorp's sample group, he actually lowers that average by omitting the company with the highest expected return—DPL, Inc. (DPL). Rothschild retained DPL in his sample for the purpose of calculating market-to-book ratio (M/B).

Staff responds that Rothschild's exclusion of DPL is justified, because the *Value Line* forecast of a 23 percent return on equity for that company is not indicative of the return investors expect could be maintained into the future. Staff notes that the 23 percent forecast is more than three standard deviations above the mean for the forecasted returns for the sample group, and that only one company earned more than 20 percent on equity in any given year out of about 150 historic earned returns reported by *Value Line*.

Staff is correct that the *Value Line* forecast for DPL is high by historical standards. The issue presented, however, is not whether to include DPL in the DCF estimate, but rather if data for the company should be used selectively in the analysis. As discussed above, Rothschild excludes DPL to estimate return on book equity, but includes the company to calculate his average M/B for the PacifiCorp sample group. This selective use of data overlooks the interrelationship between the various components of the DCF model. Given the high forecasted return on book equity, it is likely that investors have bid up DPL's stock price, which is the numerator of the M/B calculation. Because a higher stock price produces a higher M/B, it is not surprising that DPL, the company with the highest forecasted return on book equity, also has the highest M/B. Thus, we agree with PGE that Rothschild has, in effect, decreased his cost

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[32] Order No. 99-697 at 23.

of equity estimate by using DPL's relatively high stock price but excluding the company in his assessment of the expected returns that generated the higher stock price in the first place. Accordingly, we conclude that Rothschild's expected return on book equity for his second stage of his DCF calculation should be adjusted to 13.37 percent—the value Rothschild used for the last year (2004) of his first stage calculation.

Second, PGE claims that Rothschild erred in calculating the retention rate, *b*. PGE explains that, rather than relying on *Value Line* forecast, Rothschild reverts to a 2001 retention rate for his second stage growth projection. PGE observes that Rothschild's reversion to the 2001 retention rate creates a sharp discontinuity between the first and second stages in his model. PGE also contends that Rothschild provides no basis to disregard *Value Line* forecasts in his second stage. PGE notes, while he claims the current retention rate is "more consistent with investor expectations," Rothschild fails to provide any basis for that statement. PGE adds that he also failed to sufficiently explain why he used the current forecast in this docket, when he had used long-term forecasts in a prior Commission docket, UE 102.

In examining Rothschild's calculation of the retention rate, we are not persuaded that current data should be used instead of forecasted rates. To explain his switch in methodologies since docket UE 102, Rothschild refers to a large forecasted difference that existed in an intervening case, but fails to explain whether a similar difference existed in this case. He similarly fails to support his assertion that the current retention rate seems to better represent investor expectations. Indeed, Rothschild's adjustment causes a steep decline in retention ratios after 2004, reversing an upward trend forecasted by *Value Line*. We concur with PGE that the use of a forecasted retention rate should be used in this docket. We are not precluding the use of historical retention rate information in future dockets, but parties advocating such usage must justify the use of such data.

Third, PGE criticizes Rothschild's use of *Value Line* forecasts to estimate the sale of newly issued stock, the *s* term in *vs*. Although PGE admits that DCF inputs should, in general, be based on forecasts rather than historical rates, PGE contends that an exception is appropriate here, because *Value Line* does not forecast large but relatively infrequent public offerings.

Staff disagrees and believes it inappropriate for PGE to favor the use of historical data to estimate *s*, while strenuously arguing that forward-looking projections should be used for both *b* and *r*. We agree. Moreover, while we acknowledge the difficulty in predicting large offerings, PGE failed to establish that *Value Line* expressly excludes the possibility of such offerings in forecasting future sales of newly issued stock. Moreover, Staff demonstrated that the historic data is misleading, since new stock sales as a percentage of the amount of stock outstanding has been in a steep decline. Based on this record, we conclude that projections should be used to estimate the sale of newly issued stock in this docket.

PGE contends that the fourth flaw in Rothschild's multi-stage DCF model is his calculation of stock price using a mismatched M/B. PGE explains that, for each stock in the sample group, Rothschild calculated a M/B using a February 28, 2001 stock price but an estimated book value as of year-end 2000. He then used the sample average M/B rate of 1.78 to calculate a sample average 2000 stock price for his first value for market price—\$38.47.[33] PGE claims that Rothschild should have used, for his first value for market price, the actual average stock price of \$36.99.[34] By using the higher stock price, PGE contends that Rothschild drove down the cost of equity, because the higher the stock price, the lower the discount rate—which is the cost of equity in the multi-stage calculation—needed to equate future cash flows to the stock purchase price. PGE adds that the use of the correct, lower stock price, also requires reducing the M/B, since the stock price serves as the numerator in that calculation. Otherwise, PGE explains, the cost of equity will be overstated.

Further, PGE claims that Rothschild used the wrong denominator for his M/B. PGE observes that, for this figure, Rothschild used *Value Line's* estimated book value for the sample for year-end 2000, which ignores the growth in book value expected to occur by February 28, 2001. Thus, PGE contends that, in his analysis, Rothschild should have added to the year-end book value one-sixth of the expected growth in 2001. This, according to PGE, results in a book value of \$21.70, and a M/B of 1.70. PGE adds that this lower M/B results in lower proceeds from the sale of stock and, all things being equal, reduces the cost of equity.

We agree with PGE's observations and conclude that Rothschild's multi-stage DCF estimates should be adjusted so that the average stock price on February 28, 2001 of \$36.99 is used for the hypothetical stock purchase. There is no explanation why an investor would irrationally pay \$38.47 for a stock that he or she can buy on the market for \$36.99. Moreover, because of this adjustment, both the numerator and denominator of Rothschild's M/B calculation should also be modified. For the numerator, Rothschild should have used the average stock price of \$36.99; for the denominator, Rothschild should have increased year-end 2000 book values by one-sixth of the increase in the estimated year-end 2001 book values.

2. Capital Asset Pricing Model (CAPM)

Another method of estimating cost of equity is the CAPM. The CAPM is a risk premium analysis that calculates the expected equity return by adding a risk premium to a "risk free" rate of return. Risk is represented by the term "beta," which measures the stock's volatility relative to the market as a whole. The beta for the market is equal to one. Therefore, a stock with a beta greater than one is more risky than the average stock, while a stock with a beta of less than one is less risky than the average stock. The risk premium is generally calculated by multiplying the company's beta by the difference between the expected market return and the risk free rate. The formula is generally stated as follows:

$$K_e = \text{Risk-free rate} + \text{beta (market risk premium)}$$

CAPM Estimates

Only Staff presents ROE estimates based on the CAPM. Conway's CAPM analysis relies on the traditional formula set forth above. Assuming that investors have intermediate-term investment horizons, Conway calculates a risk-free rate based on an average of intermediate-term U.S. Treasury notes. Averaging the yields-to-maturity of the 5-, 7-, and

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[33] *See* Staff/702, Rothschild Schedule JAR 5, page 1, column 9.

[34] *See* Staff/701, Rothschild Schedule JAR 3, page 1, column 5.

10-year U.S. Treasury securities quoted in the March 21, 2001 edition of *The Wall Street Journal*, Conway calculates a risk free rate of 4.7 percent.[35]

Using Staff's traditional Fisher-Kamin method and a new GARCH approach,[36] Conway then calculates a beta for his sample group of electric utility companies of between 0.26 and 0.29. He estimates the sample companies beta by "regressing" their stock returns—minus a risk-free proxy rate—on the combined portfolio of NYSE/AMEX/NASDAQ stock returns—minus a risk-free rate proxy. Conway notes that his beta calculations may require some subjective adjustment, because they are significantly lower than historical beta estimates. Noting that 5-, 7-, and 10-year moving averages for beta estimates are 0.40, 0.42, and 0.44, respectively, Conway believes it is reasonable for the Commission to rely on the longer-term historical beta in this docket.

To estimate the expected market risk premium, Conway assumes that the average market risk premium over a large number of historical intermediate-term holding periods is a reasonable estimate of the expected intermediate-term market risk premium. He estimates the average historical intermediate term market risk premium by calculating the difference between expected compounded returns on the market portfolio and the compounded returns on the risk free asset over an intermediate period. The difference is then annualized.

To make his estimate, Conway uses monthly returns from 1926 to 1999 for all NYSE/AMEX/ NASDAQ stocks as a proxy for the theoretical market portfolio returns. He then estimates the risk-free rate over that period by using 1926 to 1999 data on intermediate-term U.S. Treasury securities. Next, he separates the 1926 to 1999 data into holding periods of five to ten years each, such that all the data were used just once. Finally, he calculates the average rate of return difference between holding the market portfolio and holding the risk-free rate over the intermediate-term.

Conway estimates a range of historical market-risk premia of 6.6 to 6.8 percent.[37] Inserting these figures into the CAPM formula with his beta range of 0.29 to 0.44 and a risk free rate of 4.7 percent, Conway estimates a range of cost of capital for his electric utility company sample of 6.6 to 7.7 percent.

Rothschild uses two different versions of what he calls the "CAPM/risk premium method."[38] His first version estimates the cost of equity by adding the historic inflation premium to investors' current expectation for inflation. In this calculation, Rothschild first estimates the expected rate of inflation to be 2.0 percent by comparing the yields on Treasury bonds with inflation-indexed Treasury bonds. He then adds this 2.0 percent factor to a 6.6 to 7.2 percent

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[35] In its opening brief, Staff updates the risk-free rate to 4.8 percent, based on the arithmetic average of the three U.S. Treasury rates listed in the June 20, 2001 edition of *The Wall Street Journal*.

[36] Staff explains that the GARCH approach was developed by Dr. Curt Wells, Professor of Economics at the Lund University in Sweden.

[37] Conway also derives market risk premium calculations based on the recommendations of Dr. Pettit, who reviewed Staff's risk premium estimation procedures in 1999. Utilizing Dr. Pettit's recommended approach, Conway estimates the market risk premium to be 4.5 to 4.8 percent. Conway does not rely on these estimates in his CAPM recommendation, however.

[38] Although these can fairly be called risk premium methods, we do not consider them versions of CAPM.

historic return on common stocks net of inflation to get an inflation risk premium indicated cost of equity for an investment average risk of 8.6 to 9.2 percent.

Rothschild adjusts this return to account for the lower than average market-risk for the electric utility sample group. To accomplish this, he subtracts the 4.83 percent yield on 90-day U.S. Treasury bills from the historic return on common stocks. He then multiplies this figure by the average *Value Line* beta for the PacifiCorp sample group of 0.53 to derive a 0.94 to 1.26 risk adjusted equity premium. Finally, Rothschild adds this risk adjusted equity premium back to the 6.6 to 7.2 percent range of historic returns on common stocks to derive a 7.77 to 8.09 percent risk premium for the sample group.

In his second risk premium analysis, Rothschild estimates PGE's cost of equity based on an increment to the historic annual earned returns. He makes four separate calculations using various interest rates—ranging from 4.83 to 6.71 percent—as his risk-free rate, and various market risk premia—ranging from 3.51 to 5.33 percent. Rothschild takes the average of these four calculations using both an average risk beta of 1.0 and the *Value Line* beta of 0.53 for electric utilities. Under this methodology, he produces a cost of equity range of 7.60 to 9.55 percent.

To arrive at his final recommendation, Rothschild averages the high-end and low-end of his two methodologies to obtain a range of 7.69 to 8.82 percent, with a midpoint of 8.25 percent.

Disputed CAPM Issues

PGE begins its criticism of Staff's CAPM analysis by attacking the reliability of the model itself. PGE contends that there are several problems with the CAPM model in general, and with Staff's Fisher-Kamin version of CAPM, in particular. PGE contends that these problems are so significant that the Commission cannot rely on CAPM estimates to establish an ROE for the company.

PGE argues that the most persuasive evidence against the use of CAPM in this case is the unrealistically low results it is producing. PGE observes that both Rothschild and Conway made numerous *ad hoc* adjustments to artificially inflate their CAPM results. PGE claims that Rothschild and Conway's true CAPM results are uniformly below the company's cost of new, long-term debt, which is 8.17 percent.[39] PGE contends that such low results are not consistent with financial theory—that the return on a riskier asset, like common stock, should be higher that the return on a less risky asset, like long-term debt.

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[39] PGE contends that Rothschild's true CAPM/Inflation Risk Premium results yield a range of cost of equity of 6.83 to 8.58 percent, not 7.60 to 9.55 percent as reported in his testimony. PGE asserts that Rothschild inflated his results by using, without explanation, a beta of 1.0 to calculate one of his four findings. PGE also claims that, in his inflation-based analysis, Rothschild uses an unconventional method to calculate the company-specific risk premium that increased his estimate by 94 basis points.

Similarly, PGE contends that Conway's CAPM results would have been significantly lower had he followed Staff's traditional CAPM approach or adopted the recommendations made by Drs. Wells and Pettit for calculating betas and market risk premium. For example, PGE notes that, while Conway calculated the Fisher-Kamin beta to be 0.29, he actually used a beta of 0.44 derived from a 10-year historical average. PGE believes that this adjustment is contrary to Staff's traditional endorsement of the Fisher-Kamin methodology, namely that it allows betas to change over time.

Staff defends the CAPM model and disputes PGE's specific criticisms. Staff notes that the CAPM model is a commonly accepted method of determining cost of equity and contends that the CAPM estimates here provide important insights into PGE's cost of equity. Staff acknowledges that the CAPM may be currently understating the cost of equity due to present market conditions. Nonetheless, Staff adds that Conway and Rothschild took this fact into consideration and liberally rounded up the results in their analyses.

This Commission has relied on the CAPM as an appropriate method for estimating a utility's cost of common equity for over 20 years. Recently, however, many utilities have argued against its use for reasons similar to those presented by PGE in this proceeding. To date, this Commission has rejected those arguments, concluding that the CAPM remains a viable method for determining cost of equity.[40]

We acknowledge that Staff's CAPM methodology faces its biggest challenge yet. Staff cannot escape the fact that its CAPM analyses appear to be producing results below PGE's current cost of new, long-term debt. While Staff recognizes that the CAPM may be currently understating cost of equity, it is unable to fully explain the significant drop in the Fisher-Kamin betas used in its calculations.[41] It has also failed to convince us that its upward adjustments and rounding of results have accurately and fully compensated for the current CAPM deficiencies.

While the results in this case cast further doubt on the validity of Staff's CAPM methodology, we do not believe that CAPM should be rejected in its entirety. We continue to believe that, in certain cases, CAPM analyses may provide a useful and reliable addition to the DCF results for determining cost of equity. After our review of the results in this case, however, we further conclude that the CAPM does not provide supportable and reasonable results in this docket. Accordingly, we give no weight to the CAPM results in determining an appropriate cost of equity for PGE.[42]

3. Risk Positioning Method

The Risk Positioning Method is a risk premium model that estimates the cost of equity by adding a premium for risk to a current or expected interest rate. In this analysis, PGE contends that the non-stipulated ROE decisions by regulatory bodies provide, on average, unbiased estimates of the cost of equity for electric utilities. By measuring differences between the authorized returns on equity and the yields on electric utility corporate bonds and yields on U.S. Treasuries, PGE calculates ranges of estimates of the equity risk premium. The company then adds the equity risk premia estimates to the current bond and treasury yields to derive a range for cost of equity.

In their analysis, Hager-Valach rely on approximately 500 reported, non-stipulated ROE decisions dating back to January 1983. Using the Risk Positioning Method with corporate bonds, Hager-Valach estimate a risk premium of 3.44 percent. Adding that figure to the yield from PGE's most recent non-callable bond (8.19 percent) and the yield for A-rated

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[40] *See, e.g.*, Order No. 99-697 at 19.

[41] Conway's 0.29 beta is based on data through the year 1999. Using data through the year 2000, PGE found that the Fisher-Kamin beta for companies in Conway's sample declined to 0.09—a risk figure close to that for U.S. Treasuries that are used as the "risk-free" rate in CAPM calculations.

[42] This conclusion also applies to Rothschild's "CAPM/Risk Premium" analyses.

bonds from the *S & P Bond Guide* (8.21 percent), Hager-Valach produce a range for PGE's cost of equity of 11.28 to 11.48 percent.

Hager-Valach calculate a risk premium range of 5.70 to 5.80 percent using the Risk Positioning Method with U.S. Treasury Bonds. Adding that range to the 7-year U.S. Treasury rate for 2002 using the WEFA forecast (5.39 percent), Hager-Valach calculated a range for PGE's cost of equity of 11.09 to 11.19 percent.

Staff contends that the Commission should place little weight on PGE's Risk Positioning Method for three primary reasons. At the outset, Staff notes that the proposed methodology is not a commonly accepted method for determining cost of equity. Second, Staff believes that PGE's proposed analysis is flawed, because it measures cost of equity without a review of whether the allowed return, relative to the interest rate, is more or less than the cost of equity actually demanded by investors.

Next, Staff contends that PGE's Risk Positioning Method suffers from omitted variable bias. Staff explains that, in conducting a regression analysis, it is critical to include all relevant variables to eliminate bias. While PGE admits that many factors influence commissions in setting the return on equity, such as business risk, interest rate risk, financial risk, and liquidity risk, Staff points out that the company's Risk Position Method fails to consider them, instead relying solely on lagged treasury rates. Because PGE fails to include all the relevant variables relied upon by the various commissions, Staff contends that PGE's regression equation suffers from omitted variable bias and should be rejected.

This Commission rejected a similar risk-positioning method proposed by another utility in a recent rate case.[43] We reach the same conclusion here. As Staff notes, PGE's proposed methodology using authorized ROEs and yields on treasuries and corporate bonds is unconventional and has not been accepted by other regulatory agencies as a reliable means for determining cost of equity. Because the methodology is not based on accepted regulatory principles, we decline to adopt it for use in this proceeding.

4. ROEs Authorized by other Regulatory Commissions

In addition to their DCF and Risk Positioning Method estimates, Hager-Valach rely on recent authorized ROE decisions by other regulatory commissions. Hager-Valach note that, during the last twelve months, electric utilities received an average authorized ROE of 11.6 percent, with a range of 11.0 to 12.9 percent. Because an investor will consider this type of information when making an investment, Hager-Valach believe that PGE should be awarded a common equity return within this range.

Staff objects and contends that PGE's proposal is circular in reasoning, because decisions would simply be based by looking at what other commissions allow. Staff adds that PGE's proposal would have the effect of improperly transferring to other jurisdictions the Commission's obligation of setting cost of equity for Oregon utilities. Finally, Staff notes that the Commission rejected a similar request made by NW Natural in docket UG 132:

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[43] *See, e.g.*, Order No. 99-697 at 19.

> "NW Natural contends that the Commission should rely on recent common equity return decisions made in other jurisdictions. We disagree. As Staff and NWIGU point out, there is frequently a substantial lag between the time evidence is prepared in a rate case and when a decision is finally rendered. Because interest rates have been steadily declining during the past several years, the failure to account for the regulatory lag could result in an overstatement of cost of capital. Moreover, as noted above, the authorized ROE is just one component of setting rates and is often tied to other, unknown elements in a rate case. Therefore, while other ROE determinations may provide evidence to confirm a decision, we are reluctant to base an award for NW Natural on unknowable parameters from other cases, set in other jurisdictions and different capital market conditions."[44]

PGE believes that a review of other authorized ROEs is relevant to determine investor's expectations. Because an investor views a commission decision as the utility's best estimate of the cost of equity at the time of the decision, PGE maintains that the investor will go elsewhere if the authorized ROE is set too low for the risk of the investment. PGE adds that, contrary to its argument here, Staff has previously asked the Commission to consider ROE decisions from other jurisdictions. As an example, PGE notes that Staff referred the Commission to a decision by Nevada Commission to justify its ROE recommendation in docket UG 132.[45]

We adhere to our prior determination that, while other ROE determinations may provide confirmation of a decision, they should not be used as an independent method on which to base an award. Capital market conditions, not regulatory decisions, determine a utility's cost of equity. While we agree that regulatory agencies generally make every effort to capture those conditions, a review of past decisions cannot replace an independent analysis of current market conditions and how they affect the particular utility. Moreover, ROE determinations are made not just in traditional rate cases, but also in a range of other proceedings, such as industry restructuring plans, merger approval cases, or performance-based regulatory plans. Thus, the ROE awards may have been based, in part, on other unknown parameters relevant in that particular docket.

Accordingly, we will continue to review ROEs authorized in other jurisdictions to help gauge the reasonableness of the cost of equity estimates derived from independent methodologies. We will not, however, rely on such decisions to base an ROE award for a utility.

5. Qualitative Analysis

Staff's final cost of equity estimate is based on a qualitative analysis that updates the Commission's most recent contested ROE decision. Conway notes that, in docket UG 132, Order No. 99-697, the Commission set rates for NW Natural based on a return on equity of 10.25 percent. There, the Commission adopted a market risk premium of 8.5 percent, a risk-free rate of 6.3 percent, and a beta estimate of 0.46, to obtain a rounded CAPM estimate of

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[44] Order No. 99-697 at 23.

[45] Order No. 99-697 at 24.

10.2 percent. The Commission averaged that estimate with a DCF estimate of 10.3 percent to obtain a 10.25 percent cost of equity.

Updating those figures with new information, Conway presents a range of estimates for PGE's cost of equity from 8.3 to 10.1 percent. Conway provides this range as an upper bound for ROE estimates.

While recognizing that Conway's qualitative analysis favors the company, PGE contends that it is misleading and unprincipled. PGE notes that Conway developed its upper cost of equity estimate of 10.1 percent using: (1) the Fisher-Kamin beta for NW Natural; (2) an updated 1999 estimate for the market risk premium plus 150 basis points; and (3) the 6.3 percent risk-free rate used in that prior docket. PGE questions how the 1999 beta for Northwest Natural is applicable to PGE in this case, and why Conway relies on an outdated risk-free rate even though he acknowledges that it is contrary to Commission policy. PGE believes that Conway's analysis is unprecedented and another example of the contortions through which that Staff is willing to go rather than admitting that the Fisher-Kamin CAPM is not producing realistic results.

Staff responds that PGE misrepresents its qualitative analysis. Staff explains that it provided the qualitative analysis to give an upper bound to the range of reasonable cost of equity, consistent with the Commission's internal operating guidelines.[46] Furthermore, Staff notes that its testimony made clear that the analysis illustrated various permutations and combinations of factors to update the Commission's decision in docket UG 132.

We acknowledge and commend Staff's efforts to provide additional analyses for our review of this issue. Nonetheless, we agree with PGE that the adjustments included in the qualitative analysis are not sufficiently linked to the company to provide a valid cost of equity estimate in this docket. Accordingly, we give it no weight.

Commission Resolution

We begin with the range of rates of return on common equity offered by each of the parties. For the reasons stated above, we reject the parties' single-stage DCF estimates, Staff's CAPM and risk premium calculations, PGE's Risk Positioning and Comparison to Authorized methods, and Staff's Qualitative Analysis. Focusing on PGE multi-stage DCF calculations, we adjust Hager-Valach's estimates by using *Value Line* forecasted information to calculate *s*, the growth rate of new stock. This produces a cost of equity range of 10.4 to 11.5 percent, with a mid-point of 10.95 percent.

Turning to Rothschild's multi-stage DCF analysis and using the PacifiCorp sample group and actual stock closing prices as of February 28, 2001, we first adjust his estimate by using the average forecasted retention rate, *b*, for 2004 (43.74 percent) throughout his second stage. This increases his overall cost of equity estimate to 9.89 percent. Next, we adjust Rothschild's second stage input for the expected return on book equity, *r*, by using the year 2004

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[46] Those guidelines provide that Staff is "responsible for ensuring that the record includes a range of legally supportable positions so that the Commission has options when making a final decision." Order No. 01-253, App C at 1.

value of 13.37 percent. This adjustment further increased Rothschild's DCF estimate to 10.13 percent. Finally, we correct Rothschild's inputs for the stock purchase date and price set at February 28, 2001, and adjust his M/B accordingly. This produces a final adjusted DCF estimate of 10.53 percent.

Together, these two adjusted estimates produce a cost of equity range of 10.53 to 10.95 percent, with a mid-point of 10.74 percent. We round this number to 10.75 percent. We find that this average of 10.75 percent is an appropriate cost of equity for the comparable group of electric utilities. We conclude, however, that this figure should be adjusted for PGE, whose capital structure contains a substantially higher percentage of common equity than the average for the comparative group of electric utilities.

It is well understood by finance practitioners and theoreticians that the cost of equity drops as the percentage of common equity in the capital structure increases. Because the average amount of common equity in the capital structure of the comparable group of electric companies was 45.14 percent compared to 52.16 percent for PGE, it necessarily follows that PGE has a lower cost of equity. PGE's capital structure is therefore less risky, and its cost of common equity should be adjusted accordingly.

The question therefore becomes how much of an adjustment should be made. This record contains varying estimates that the cost of equity for regulated electric utilities decrease anywhere from 4 to 13.8 basis points for each one percent increase in the level of common equity in the capital structure. We find Rothschild's proposed 25 basis point reduction to be a reasonable adjustment to account for the above average percentage of common equity in PGE's capital structure. Contrary to PGE's arguments, this reduction does not constitute a "penalty." Rather, it is simply an adjustment to acknowledge PGE's reduced financial risk due to its increased level of common equity in its capital structure. Reliance on the stipulation in docket UM 814 is reasonable for the purpose of establishing a capital structure for PGE. The stipulation, however, cannot reasonably be used to argue for an ROE that does not correspond to the adopted capital structure.

Accordingly, we will adopt this adjusted average of 10.50 percent as an appropriate and reasonable cost of equity for PGE.[47] Evidence shows that this award will allow PGE to maintain a reasonable financial structure and attract capital at a reasonable cost. Using this figure in connection with other stipulated capital costs and the company's capital structure, which we find reasonable and adopt, yields a rate of return for PGE of 9.09 percent.

Capital Component	Ratio	Cost	Weighted Cost
Long-term Debt	46.32 %	7.508 %	3.48 %
Preferred Stock	1.53 %	8.432 %	0.13 %
Common Equity	52.16 %	10.50 %	5.48 %
Total	100.00 %		9.09 %

Finally, we close this subject with a short discussion on efforts expended in this docket to fix a reasonable ROE for PGE. ROE determinations have always been a fundamental

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[47] Given this conclusion, we need not address PGE's argument that Staff's ROE recommendation, if adopted, would impair the company's bond ratings.

part of utility regulation and, despite a decline in the frequency of traditional utility rate cases, continue to play an important role in ratemaking. The task of determining a reasonable ROE, however, is often one of the most difficult and contentious aspects of a rate case proceeding. This docket was no different. PGE and Staff presented ROE testimony from seven witnesses and submitted over 600 pages of prefiled testimony and supporting documents. They required two full days of hearing on the ROE issue, at which they introduced approximately 30 new exhibits. After hearing, PGE and Staff produced over 100 pages of legal argument on the issue, and spent a majority of their time at oral argument addressing the issue to the Commission.

We recognize the inherent complexity of the issue, and that it may be impossible to devise a method to make the process of determining a reasonable ROE an agreeable one. Others with more time and expertise have tried to establish a consensus on the overall efficacy of ROE techniques and methodologies, but failed. It appears that contention over ROE is unavoidable. Nonetheless, while we recognize our inability to make the ROE process easy, we believe that the adoption of certain principles on this matter will make the process of setting a reasonable ROE easier. Based on our experience in this and in other dockets, we offer guidelines, set forth in Appendix A, for witnesses providing cost of equity recommendations.

II. PRICING

The parties to this docket largely agree with PGE's proposed pricing structure, tariff building blocks, rules and regulations, rate design and rate spread. ICNU, OSM, and OOE disagree with specific proposals, which we address below.

1. Customer Impact Offset

To help mitigate the rate impact on customers, PGE proposes to limit rate increases to not more than 150 percent of the overall average increase in base rates. Consequently, PGE proposes prices for Schedules 38, 48, 49, 93, and 97, that are less than the cost of service. To offset the revenue lost by this limitation and the effect of certain special contracts, PGE proposes to increase the energy charges of the remaining schedules.

While it acknowledges the need to mitigate large rate increases, ICNU contends that it is equally important to have an orderly transition to cost-based rates. Therefore, rather than embed a subsidy in base rates, ICNU recommends that PGE establish an adjustment schedule to phase out the customer impact offset over a two- to five-year period. ICNU explains that the adjustment schedule should be implemented such that, once a year, prices are increased for schedules whose prices are significantly below the long run incremental cost (LRIC) of service and reduced by a corresponding amount for the remaining schedules.

Commission Resolution

If adopted, ICNU's proposal would move all customers to LRIC in as little as two years, essentially eliminating the customer impact offset. Even under a full five-year period, the Commission would be required to determine how much certain rates should be increased, resulting in administrative difficulty and confusing price changes. In the past, this Commission has phased out the customer impact offset and similar offsets in conjunction with other general rate changes. We affirm that practice, which allows us the opportunity to consider the impact of rate changes on all customer classes at the time that general rates are being changed.

2. Non-Conforming Load Charge

PGE's proposed Schedule 83 and 583 includes a Nonconforming Load Charge of $5.60 per kW/month.[48] PGE explains that this charge is needed to offset the costs required to maintain generating capacity for these highly variable loads.

OSM contends that PGE failed to establish that the charge is either necessary or that the amount is appropriate. Therefore, OSM asks the Commission to reject the proposed charge. In the alternative, OSM requests that, if the Commission determines a special charge is necessary to cover the cost of load following and load regulation for highly variable loads, the charge should be based on the actual costs associated with providing the service.

Commission Resolution

We conclude that PGE's proposed non-conforming load charge is premature. PGE admits that no customers will be subject to the charge until 2004. While PGE claims that the charge is proposed to recover the costs of regulating capacity, it is not known what those costs will be at that future date to serve these variable loads. Accordingly, we reject PGE's proposed non-conforming load charge. During the next three years, PGE will have the opportunity to observe industry developments and propose, at a more timely date, an appropriate charge for load following and load regulation for non-conforming loads.

III. OTHER ISSUES

1. Emergency Default Service

PGE's Schedule 82 is designed to provide back-up service for any direct-access customer that loses its Electricity Service Supplier (ESS) and has not provided PGE with the notice required to receive service under the applicable standard offer service rate. PGE proposes to provide Emergency Default Service under Schedule 82 on a restricted "as available" basis. Schedule 82, as proposed, provides in part:

> "In all territory served by the Company, Emergency Default Service shall be provided by the Company as available. The Company may restrict customer loads returning to this schedule if it experiences constraints in the availability of electricity."

PGE explains that the purpose of the "as available" language is to prevent a returning direct access customer from causing PGE to curtail service to other customers who did not go to direct access or who are already on Schedule 82. Without limiting the availability of emergency default service, PGE explains that these direct access customers—who do not pay to have backup resources in case their ESS fails—would have the ability to get firm service under

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[48] PGE defines "nonconforming loads" as consumer loads grater than 10 MW that routinely cycle up and down during the course of the day at a rate of at least 10 MW per minute.

Schedule 82 for free. PGE contends that other customers should not be required to suffer rolling outages to provide emergency default service or to pay for standby resources for direct access customers.

Staff and ICNU contend that PGE's proposal is discriminatory and could act as a barrier to competition. Because PGE remains the provider of last resort within its service territory, Staff notes that the company is obligated to provide safe and adequate service to all customers within its service area regardless of whether the customer is returning to utility service or has remained as a PGE customer. Thus, Staff contends that PGE should not be permitted to treat customers who choose direct access and subsequently return to PGE's Schedule 82 differently than other customers within its territory.

ICNU adds that ORS 757.622 requires the Commission establish terms and conditions for emergency default service for direct access customers that "provide for viable competition among electricity service suppliers." It adds that any customer with critical reliability concerns or large costs associated with a disruption of service could be dissuaded from going to direct access under PGE's proposed Schedule 82.

Commission Resolution

We share ICNU and Staff's concerns. For the successful implementation of SB 1149, it is important that direct access customers be treated equally to those customers who remain with the utility. For that reason, we agree that customers who choose direct access should not be limited to default service on an "as available" basis. We are not persuaded by PGE's claims that the restriction is necessary to protect existing customers. As ICNU notes, PGE's argument focuses on extreme conditions when power is not available at any price and rolling blackouts are imminent. Under such conditions, PGE's ability to offer Schedule 82 on an "as available" basis would not guarantee service reliability for existing customers. Furthermore, contrary to PGE's claim, returning customers would not be receiving firm service under Schedule 82 for free. In its filing, PGE proposes to charge a 25 percent premium on the Dow Jones Mid-Columbia Daily on-peak and off-peak Firm Electricity Price Index for emergency default service under Schedule 82. While PGE claims in its brief that this premium covers only the administrative costs, its testimony explains that the premium is necessary to mitigate the risk associated with the supply of emergency default service and "to cover the unpredictable nature of service under this rate."[49]

PGE's Rule K Curtailment Plan specifies that the utility may initiate certain actions "when necessary or prudent to protect the performance, integrity, reliability, or stability of the Company's electrical system or any electrical system with which it is connected." We agree with ICNU that PGE should follow the Rule K procedures for Schedule 82 customers under short-term emergencies. Accordingly, we adopt ICNU's recommendation that PGE's Schedule 82 conditions be modified so that the "Available" section reads:

> "In all territory served by the Company. The Company may restrict Consumer load returning to this schedule in accordance

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[49] *See* PGE/100, Fowler-Lesh at 12.

> with Rule K, Curtailment Plan and Stage 5 Utility Actions under short-term emergency conditions."

2. Refusal of DASR

A Direct Access Service Request (DASR) is an electronic notification provided by an ESS to PGE that a customer has selected the notifying ESS as the customer's supplier of electricity service. As applicable here, PGE proposes that the company should have the authority to refuse a DASR when:

> (1) The Company has not received full payment from the Consumer for past due amounts or other obligations related to regulated charges from a Consumer's prior Electricity Service account(s) unless such charges are part of a pending Consumer dispute; or
>
> (2) The Company has not received full payment or the Consumer or ESS has not made an arrangement to pay the balance on an existing Budget Payment Option or other agreements.[50]

Staff objects to PGE's proposal and believes that, if the ESS has not paid PGE, the customer should not be held hostage and not be allowed to switch electricity suppliers. It contends that the consumer should be allowed to switch and that PGE should address non-payment issues through its disconnection policies. PGE responds that Staff's proposal simply creates a potential conflict between PGE, the customer and ESS. It contends that it would be simpler to allow the company to refuse the request until past due amounts are paid, rather than requiring it to make the switch and then subsequently disconnect the customer from its new service supplier for non-payment of past bills.

Commission Resolution

Both parties raise valid concerns. A customer should not be held hostage due to the misconduct of its ESS. At the same time, however, it would be confusing and administratively burdensome for the company to switch a customer to a new ESS, then disconnect the customer for unpaid charges from a prior account. We believe it is appropriate to focus on the party at fault. PGE's Rule H should be amended to allow the company the limited ability to refuse a request for direct access for a customer if that customer has not fully paid PGE for prior regulated services rendered. PGE should not be allowed to refuse a DASR where the ESS, not the end-user customer, has failed to make full payment.

3. Offsetting Termination Payments

PGE has proposed that its ESS service agreement allow any termination payment owed to the defaulting party to be offset against any amounts due or owed by the defaulting party

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[50] *See* Advice No. 00-14, PUC Oregon No. E-17, Original Sheet No. H-15, as marked in copy attached to PGE's Opening Brief.

or any of its affiliates to the non-defaulting party. ICNU does not dispute the ability to offset, but contends that it is not industry practice for the offset to include the non-defaulting party's affiliate under any other agreements.

Commission Resolution

We disagree with ICNU's contention. As PGE explains, the language contained in the ESS service agreement was modeled after the Edison Electric Institute Master Purchase and Sale Agreement, which is becoming the model for power purchase and sales agreements throughout the country.

4. Portfolio Fees

PGE's proposed Rule J addresses eligibility requirements and enrollment terms and procedures for residential and small non-residential customers participating in the portfolio options and standard offer service. After an initial free enrollment period, PGE proposes to charge residential customers a $5.00 fee each time a portfolio selection is made or changed. PGE proposes a $20 switching fee for small non-residential customers moving between portfolio options or switching to or from direct access or the standard energy offer.

CUB and Portland believe that PGE's proposed switching fees will create economic disincentives for customers to exercise choice. Portland contends that PGE should recover any administrative costs by recovery through rates, not by separate fees to individual customers. Portland recommends that PGE recover the modest costs associated with option enrollment and switching through the basic charge. Portland maintains that a separate charge would be confusing and unnecessary, and impede access to new electricity options.

Commission Resolution

We first note that PGE's proposed fees are authorized by OAR 860-038-0220(9)(e), which provides that "an electric company may impose nonrecurring charges to recover the administrative costs of changing suppliers or rate options." CUB and Portland offer no evidence that the proposed fees are so high as to prevent a customer from switching services or providers. In fact, as PGE notes, many service providers might offer to pay any switching fees, as is common in the telecommunications industry. We find no reason why PGE should not be allowed to charge these fees to customers on a cost-causation basis under the SB 1149 rules.

5. Purchase of Transmission Services

In its Schedule 600, PGE proposes the requirement that an ESS must purchase firm transmission service on a monthly basis under PGE's Open Access Transmission Tariff. Portland contends that the minimum duration of purchase of transmission services by ESSs should be reduced from one month to one day. Portland notes that PGE's merchant function can purchase transmission services for as little as one day.

Commission Resolution

We are not persuaded by Portland's argument. As PGE notes, Portland attempts to compare transmission for merchant trading with transmission to serve retail load. PGE must secure transmission service for its retail service customers on a firm basis to ensure reliable service. ESSs should not be allowed to provide any less reliable transmission services. Indeed, OAR 860-038-0590(2) requires electric companies to coordinate the filings of tariffs "to ensure that all retail and direct access customers are offered comparable services at comparable prices." Moreover, if ESSs were to purchase non-firm transmission on a daily basis, they would run the risk that no transmission would be available on certain days because firm purchasers take priority over the short-term and non-firm purchasers. We believe that, like PGE, ESSs should be required to secure firm transmission on a long-term basis.

6. Merchant Trading Fee

Staff seeks to impose a one-half percent fee on the absolute value of all PGE's Merchant Trading Activity. Staff proposes the fee to compensate ratepayers for the use of expertise gained in PGE's regulated trading operations. It believes that PGE's unregulated Merchant Trading activity benefits from the knowledge and expertise its traders gain from conducting trades for the company's retail customers.

PGE objects to the proposed fee. It contends that the fee is prohibited by the stipulation approved by the Commission in the Enron-PGE merger, docket UM 814, in which PGE agreed to pay ratepayers $105 million for the expertise used or to be used in PGE's unregulated wholesale trading activities. It relies on Paragraph 20A of that stipulation, which provides, in relevant part:

> "Enron and PGE are obligated to provide PGE's customers $105 million upon merger completion, which represents full payment for any entitlement PGE's customers may have to value that relates to:
>
> > (1) use of PGE's name, reputation, business relationships, expertise, goodwill or other intangibles;
> >
> > (2) wholesale and non-franchise retail activities that PGE has undertaken that will not take place within PGE after the merger (this includes but is not limited to PGE's discontinued term wholesale trading and risk management activities), and wholesale and non-franchise retail activities that PGE might have undertaken had the merger with Enron not occurred; and,
> >
> > (3) added value of the merged entity that is achievable because of the combination or because of the association with PGE.

> This payment obligation also shall constitute full payment to PGE's customers for any entitlement to the revenues, value or other benefits arising from the business activities of the merged entity, other than the regulated business activities conducted by PGE. The term 'regulated business activities' shall mean the assets and services of PGE which are subject to economic regulation under Oregon or federal law."[51]

PGE contends that Staff's proposed fee violates: (1) the release relating to all future customer claims to PGE's expertise set forth in Condition 20(A)(1); (2) the release relating to wholesale and non-franchise retail sales the PGE might have undertaken had the merger not occurred, as stated in Condition 20(A)(2); and (3) the release as it relates to unregulated activities of the merged entity set forth in the final paragraph. Staff responds that the stipulation anticipated that PGE would discontinue wholesale trading after the merger with Enron. Thus, Staff contends, the stipulated $105 million payment applies only to wholesale trading activities that PGE had engaged in prior to, but not after the merger.

Commission Resolution

The wording of the stipulation is ambiguous, and our ability to determine the parties' intent in drafting the language is frustrated by the fact that, at the time of entering the stipulation, both PGE and Staff believed that PGE would permanently discontinue its Merchant Trading activities. We need not, however, resolve the issue of whether Staff's proposed fee is barred by the merger stipulation. Even assuming that the PGE-Enron merger does not control, we agree with PGE's alternative argument that Staff's Merchant Trading fee proposal lacks sufficient evidentiary support.[52]

Both Staff and PGE agree that benefits of trading expertise and information flow both ways between the company's Retail and Merchant Trading activities. The combination of functions give the Merchant Trading operations access to information about regulated utility operations that is generally not available to independent trading operations. At the same time, the company's Retail Trading operations gain greater access to price information as a result of the contacts made through Merchant Trading. The combination of functions also enables PGE to leverage better terms for purchases to meet retail load requirements.

There is nothing in this record, however, that sufficiently quantifies the value of this expertise and information. Consequently, we are unable to determine whether the flow of this information is, as Staff believes, so unbalanced as to require the imposition of a fee on PGE's Merchant Trading activity. Indeed, there is no empirical evidence to establish that the value of information and expertise that PGE's Merchant Trading operation receives is greater than the value of the information and expertise that it provides to the company's Retail Trading activities. Moreover, there has been no analysis on what effect Staff's proposal may have on retail rates, as the imposition of a trading fee would provide the company incentive to transfer the Merchant Trading activity to an unregulated affiliate.

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[51] Order No. 97-196 at Appendix A, page 6.

[52] In light of this conclusion, we also need not address PGE's motion to strike Staff's testimony relating to the proposed Merchant Trading Fee.

In short, we find that the synergies of joint trading operations flow both ways between PGE's retail and Merchant Trading operations. In the absence of any evidence that establishes that the flow of this expertise and information is unbalanced in favor of PGE's unregulated operations, we reject Staff's proposal to adopt a one-half percent fee on the absolute value of all PGE's Merchant Trading Activity.

CONCLUSIONS

1. PGE is a public utility subject to the Commission's jurisdiction.

2. The stipulations, attached as Appendix C, D, E, and F, should be adopted. The results contained in the revenue requirement stipulation, attached as Appendix B, should be adopted with the additional adjustments to non-power O&M costs described above.

3. Based on the record in this case, PGE's rates that result from the stipulations and the Commission's conclusions in the body of this order are just and reasonable. A results of operations spreadsheet is attached as Appendix G.

ORDER

IT IS ORDERED that:

1. Advice No. 00-14, filed by Portland General Electric Company on October 2, 2000, is permanently suspended.

2. The stipulations attached as Appendices C, D, E, and F are adopted in their entirety.

3. The results contained in the stipulation attached as Appendix B are adopted, with the additional adjustments to non-power O&M costs described above.

4. In its September 12, 2001 power cost filing, PGE shall submit a rate design table identifying, for each rate schedule, the specific percentage increase resulting from the updated power cost estimates and consistent with the terms of this order.

5. PGE may file revised tariffs consistent with findings of fact and conclusions of law contained in this order, to be effective no earlier than October 1, 2001.

Made, entered, and effective AUG 31 2001

Roy Hemmingway

Roy Hemmingway
Chairman

Roger Hamilton

Roger Hamilton
Commissioner

Joan H. Smith
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

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 to a court pursuant to applicable law.

GUIDELINES FOR COST OF EQUITY WITNESSES

When providing cost of equity recommendation in Commission proceedings, witnesses should bear in mind the following guidelines:

- Clarity: All witnesses should clearly and fully explain the methodologies used and the theoretical support for using the methodologies. When advocating a new approach, or one previously rejected by the Commission, a witness should explain why the Commission should adopt the proposed methodology in the present docket.
- Candor: All witnesses should clearly explain the use of every subjective adjustment and explain the reasons for making them, whether they are based on academic literature, personal judgment, or other reasons. The witnesses should include any such explanations in the text of their testimony, rather than bury them in footnotes, work papers, or appendices.
- Reproducible Results: All witnesses should clearly explain every formula, calculation, and adjustment used in sufficient detail to allow other parties and the Commission the ability to easily reproduce and adjust their results. If necessary, the witnesses should include electronic spreadsheets and step-by-step instructions for use.
- Professionalism: When challenging the opinions offered by others, witnesses should exercise a high degree of professionalism. While the Commission must consider the credibility of witnesses, the emphasis in testimony and briefs should be on the evidence presented, not the integrity of opposing witnesses. Criticism of opposing testimonies should be clearly articulated and objectively supported. Before criticizing other positions, witnesses should ensure that their own opinions are properly supported and clear.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

RECEIVED

APR 26 2001

Public Utility Commission of Oregon
Administrative Hearings Division

UE 115

In the Matter of PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	)))	STIPULATION REGARDING CHANGES TO PGE'S REQUESTED COST OF SERVICE

This Stipulation is entered into for the purpose of resolving specified adjustments to Portland General Electric Company's (PGE) requested revenue requirements in this docket. This Stipulation presents a partial settlement of revenue requirement issues and does not resolve all issues in this docket.

I. INTRODUCTION

On October 2, 2000, PGE filed Advice No. 00-14 to produce a $324 million increase in its base prices to its customers. The filing was based on a projected test year of 2002. Advice No. 00-14 was suspended by the Commission at its October 20, 2000 Public Meeting, Order No. 00-669.

The Administrative Law Judge held a Prehearing Conference on October 24, 2000 to establish a procedural schedule in the case. Pursuant to that schedule, Staff and Intervenors published settlement proposals on January 12, 2001. Settlement Conferences commenced January 16 through 19 and were continued to January 23, January 26, January 30, and February 1. The Settlement Conferences were open to all parties.

As a result of the settlement conferences, the parties signing this Stipulation (Parties) have agreed to a reduction in PGE's requested revenue requirement with respect to specified adjustments. The Parties submit this Stipulation to the Commission and request that the Commission approve the settlement as presented.

II. TERMS OF STIPULATION

1. The Parties to this Stipulation agree that PGE will reduce its revenue requirement request to reflect the adjustments listed in Attachment A to this Stipulation. The parties agree to calculate the revenue requirement impact of the adjustments listed in Attachment A consistent with the final Commission approved Cost of Capital in this case.

2. The Parties recommend that the Commission approve the various tariff, rule, rate base, expense and other revenue adjustments described in Attachment A.

3. The Parties request the Commission allow PGE to place certain items in supplemental tariffs. Specifically, the Parties request that adjustments S-22 (Y2K Deferral), S-38 (1999 Y2K Amortization), S-39 (Neil Settlement), S-42 (Property Sale Gains), and S-46 (Non-recurring property sales) be placed in supplemental tariffs.

4. The parties agree to work in good faith to agree on the unbundling of the stipulated adjustments in Attachment A in accordance with OAR 860-038-0200. Absent agreement on unbundling the adjustments in Attachment A, such adjustments will be unbundled pursuant to the unbundling approved in the final order of the Commission.

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

6. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein.

7. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that departs from the terms of this Stipulation, the Parties to this Stipulation 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 Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

8. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving this Stipulation, any Party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's order.

9. By entering into the Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principals, methods or theories employed by any other party in arriving at the terms of 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.

10. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each Party on the date entered below.

Dated this 7th day of March, 2001.

PORTLAND GENERAL ELECTRIC COMPANY	INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES
By: J. Jeffrey Dudley	By:
PACIFICORP	FRED MEYER STORES
By:	By:
STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON	CITIZENS' UTILITY BOARD
David B. Hatton By: David B. Hatton	By:
OTHER	
By:	

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This Stipulation is entered into by each Party on the date entered below.

Dated this 7th day of March, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

By: ______________________

PACIFICORP

By: ______________________

FRED MEYER STORES

Michael L. Kurtz

By: ______________________

CITIZENS' UTILITY BOARD

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

OTHER

By: ______________________

Attachment "A"

The Stipulated Adjustments are described below and summarized in Attachments A1 (Cost of Capital), A2 (Other Revenue, Operating Costs and Rate Base), A3 (Tariff Language Revisions), A4 (Schedule 48 & 105, Rules B-G, I, K and L) and A5 (Tariff Schedule Review). The adjustments below do not include the impact of revenue sensitive costs (e.g., taxes and bad debt expense). The revenue requirement impact of each of the adjustments (including revenue sensitive costs) will be determined once the Cost of Capital issue (S-0) is settled.

S-0 Cost of Capital: The parties agree on the capital structure, cost of preferred stock, and cost of long-term debt as provided in Attachment A-1. No stipulation on the cost of equity at this time.

S-1 FERC Wholesale Fee: Reduce A&G expenses by $372,000.

S-2 Montana Production Tax: Increase Taxes Other Than Income by $450,000.

S-3: Colstrip O&M: Increase Production O&M by $1,043,000 and increase Transmission O&M by $25,000.

S-4: Transmission O&M: All Transmission O&M issues are addressed under Staff issue S-30.

S-5: FERC Hydro Fee: Reduce Production O&M by $14,000 and increase A&G expense by $714,000.

S-6: Income Tax Apportionment: This adjustment is incorporated into Staff issue S-41.

S-7: Trojan Severance Program: Increase Amortization by $66,000 to reflect a three-year recovery of the unamortized balance at October 1, 2001.

S-8: Oregon Analytical Lab Sale: Reduce Production O&M by $83,000, Transmission O&M by $28,000, Distribution O&M by $223,000, and rate base by $439,000. Increase A&G expense by $108,000 and Amortization by $100,000.

S-9: PGH Billings: Reduce A&G expense by $436,000.

S-10: Retail Unbundling: Increase Customer Service expense by $435,000 and A&G expense by $303,000.

S-11: Beaver Turbine: Increase Depreciation by $182,000, Property Taxes by $14,000, and rate base by $2,789,000.

S-12: Other Revenue: This item is considered under Staff issue S-24.

S-13: State Tax Credit: This adjustment is incorporated into Staff issue S-41.

S-14: SERP Rate Base & MDCP expense: Decrease A&G Expense by $4,645,000 and rate base by $2,122,000.

S-15: Remove Trojan: Reduce Amortization expense by $16,584,000 and rate base by $102,904,000 to comply with the Commission Order No. 00-601 in Docket UM-989.

S-16: Remove NEIL: Increase Production O&M by $2,400,000 and A&G by $1,418,000 to comply with the Commission Order No. 00-601 in Docket UM-989.

S-17: Remove Other Debits & Credits: Decrease Other Revenue by $589,000 and Amortization by $959,000. Increase rate base by $181,000. This complies with the Commission Order in Order No. 00-601 in Docket UM-989.

S-18: Solar for Schools: Reduce Customer Service costs by $55,000 to reflect removal of the cost of this program as a regulated activity.

S-19: Salmon Spring Reclassification: Increase Other Revenue by $183,000.

S-20: Green Power Purchase: Reduce Purchased Power by $420,000.

S-21: Property Tax Unbundling Correction: Transfer $902,000 of property taxes from Transmission to Production.

S-22: Y2K Deferral: Incremental Y2K costs incurred in 2000 will not be recovered through base rates in UE-115. Accordingly, there will be no adjustment in item S-22. The parties further agree that PGE will collect the unamortized balance of these 2000 Y2K costs at 10-1-01 through a balancing account (approximately $363,000) and supplemental tariff. The balancing account will accrue interest at PGE's last approved cost of capital.

Recovery of the 2000 Y2k costs is subject to a prudence review by Staff. Staff will attempt to complete the review before June 1, 2001.

S-23: Two-Cities: Increase Wheeling expense by $129,000 and rate base by $96,000.

S-24: Misc. Electric Revenue: Increase Other Revenue by $998,000.

S-25: Variable Power Cost: No stipulation at this time.

S-26: Customer Acct. Non-Labor: Reduce Customer Service costs by $1,600,000.

S-27: Category A Advertising: The parties agree to include in base rates Category A advertising costs equal to 1/8 of one percent (.125 percent) of revenues in accordance with OAR 860-026-0022(3)(a). Based on PGE's filed revenue requirement, this results in a reduction of $2,405,000 in Customer Service costs. The parties agree that this calculation will be updated to reflect the final Commission approved revenue requirement in this case.

The Parties further agree that PGE may defer (for future amortization in rates) amounts spent in excess of the final approved amount for the twelve month period starting when UE-115 rates go into effect subject to Staff audit of all Category A advertising and related expenses. This is an annual deferral that continues until new base rates are established. Interest will accrue on deferred amounts at PGE's most recently approved cost of capital. The Parties agree that the mechanism described above is an automatic adjustment mechanism and no earnings test is required.

S-28: Public Purpose Adjustment: Reduce A&G expense by $149,000 to reflect removal of Lighting Lab costs. Remove $550,000 from Customer Service expense for DSM Evaluation and Verification (E&V) costs. The parties agree that the DSM E&V costs may be deferred and recovered through Schedule 101 subject to a review of prudence by the Staff. Deferral will continue until all energy efficiency programs receiving lost revenue recovery are closed out. The Parties agree that the mechanism described above is an automatic adjustment mechanism and no earnings test is required.

S-29: Marketing and Sales Expense: Reduce Customer Service expense by $800,000.

S-30: Transmission & Distribution O&M: Reduce Transmission O&M by $1,505,000 and Distribution O&M by $990,000. The Open Access Transmission Tariff (OATT) and intertie revenue will be revised based on the final transmission revenue requirement. This update cannot occur until the cost of capital (Issue S-0) is finalized.

S-31: A&G Accounts: Reduce A&G expense by $1,000,000.

S-32: SERP O&M: Reduce A&G by $1,250,000.

S-33: Bonus/Incentive Pay: Reduce A&G expense by $2,237,000, payroll taxes by $240,000, and rate base by $602,000.

S-34: Workforce Level: Reduce A&G expense by $4,821,000, payroll taxes by $518,000 and rate base by $1,046,000.

S-35: OPUC Wage Formula: Reduce A&G expense by $1,550,000, payroll taxes by $167,000, and rate base by $336,000.

S-36: Distribution Plant: Reduce net average plant by $2,000,000, Depreciation expense by $60,000, and Property Taxes by $30,000. Sales to Consumers is increased by $1,075,452.

S-37: Materials and Supplies: Reduce rate base by $3,681,000.

S-38: Y2K Amortization: The parties agree that PGE should recover the unamortized balance of 1999 incremental Y2K costs deferred through a supplemental tariff versus base rates as initially proposed by PGE. Accordingly, reduce Amortization expense by $1,977,000 and rate base by $4,942,000. The unamortized balance at 10-1-01 will be placed in a balancing account, accruing interest at PGE's last approved cost of capital, for future amortization in rates through a supplemental tariff.

S-39: NEIL Amortization: The parties agree that PGE should refund amounts due to customers resulting from the settlement of NEIL through a balancing account, accruing interest at PGE's last approved cost of capital, and supplemental tariff. Accordingly, there is no adjustment for issue S-39.

S-40: Acc. Deferred Taxes: Reduce rate base by $22,832,000.

S-41: Income Tax Adjustments: The parties agree that the composite state income tax rate for the UE-115 filing is 6.6547%, that PGE will incorporate $917,000 in expected state income tax credits into the final calculation of test year state income tax expense, and that the interest deduction for tax purposes will be calculated consistent with the weighted cost of debt, as provided in Attachment A1 to this Stipulation, and the final approved rate base total in this case. The S-41 adjustment will be calculated after all the component factors are finalized.

S-42: Property Sale Gains: Starting the later of 10-01-01 or the date UE-115 rates go into effect, PGE will assign actual gains and losses from the sale of utility property into a balancing account for later refund or collection from customers in a supplemental tariff. The balancing account will accrue interest at PGE's last approved cost of capital. Accordingly, increase Amortization expense by $477,000 to reflect the removal of forecast property sale gains/losses from the calculation of PGE's base rates.

S-43: Depreciation Study: Reduce Depreciation expense by $3,567,000 and increase rate base by $1,784,000 to reflect the stipulation in Docket UM-982, Order No. 01-123.

S-44: SB 1149 Implementation Costs: Increase A&G expense by $416,000, Customer Service expense by $376,000, and Rate Base by $459,000. Certain prudently incurred expenses only occur in 2002. Those one-time expenses are included in rates at 1/6'th of the 2002 amount and are also included in rate base, based on a six-year average. The adjustments listed previously incorporate the six year recovery of the one-time costs.

S-45: CIS/IT Capital Costs: PGE will place into base rates, 100% of the 2002 revenue requirement related to the 2000, 2001 and 2002 capital additions for the CIS/IT capital items listed below. The 2002 revenue requirement included in base rates will be trued-up to the actual revenue requirement for the CIS/IT capital costs. OPUC Staff will audit PGE's actual capital expenditures for the CIS/IT capital items below. Only those CIS/IT costs that are deemed reasonable and prudent will be authorized for inclusion in the "actual" revenue requirement calculation. Accordingly, relative to the CIS/IT costs included in UE-115 base rates, customers will receive a refund for any CIS/IT costs PGE does not expend or CIS/IT costs the OPUC rules imprudent. This ensures customers will only pay for prudently incurred CIS/IT costs.

UE-115 2000-2002 CIS/IT Capital Items

A) Customer Information System (CIS).
B) Enterprise Resource Planning (ERP) system.
C) Network Meter Reading (NMR) backbone and data store (excluding the meters).
D) Miscellaneous capitalized information technology costs.

The amount of the 2000-2002 gross capital additions included in the UE-115 filing for the CIS/IT capital items is $96.85 million.

Audit / Deferral Process

Prior to April 1, 2003, PGE will report to the Commission Staff its 2000-2002 capital expenditures for the CIS/IT capital items. Staff will audit PGE's information technology programs and expenditures at any time, but will complete their audit by June 1, 2003. If PGE disagrees with the results of Staff's audit, PGE may present their concerns to the Commission who will decide which CIS/IT costs are recoverable. Based on the "actual" CIS/IT costs approved by the Commission/Staff, PGE will calculate its "actual" revenue requirement. If the actual 2002 revenue requirement is less than the base rate 2002 revenue requirement, the difference will be deferred in a balancing account for future refund to customers. The balancing account will accrue interest at PGE's last approved cost of capital. The balancing account will presume the deferral was known and measurable as of January 1, 2003, and will accrue interest from that date forward. PGE agrees to waive an earnings review if one is required to implement the potential refund.

It is possible that some of the forecasted CIS/IT capital items will be delayed and not expended until 2003. If there are expenditures in 2003, the above audit process will be repeated in 2004 for the incremental 2003 expenditures. The actual revenue requirement for the 2003 expenditures will be added to the actual revenue requirement for 2002, this combined actual revenue requirement will be compared to the base rate 2002 revenue requirement. If the combined actual revenue requirement is less than the 2002 base revenue requirement, the difference will be deferred in the balancing account with an effective date of January 1, 2004. Each January 1st thereafter, an amount equal to the 2003 true-up will be deferred in the balancing account. The annual deferrals will terminate when new base rates are established.

To facilitate the audit process, Staff will receive and be an active participant in existing PGE processes for monthly or quarterly monitoring and/or progress reports for PGE's information technology projects. Staff's audit will focus on determining whether the information technology systems are providing reasonable performance and are used and useful.

S-46 Supplemental Amortization Tariff – Nonrecurring Property Sales: PGE will refund the items listed below (including any applicable interest) to customers through a supplemental tariff. The start date of the amortization will be established separate from this Stipulation.

- The $2,179,000 of property transactions listed in PGE Exhibit/209, Barnes 1.
- The $2,500,000 per the Trojan Offset Settlement, Order No. 00-601.
- The $10,468,236 gain from the sale of the Coyote II Common Facilities, Order No. 00-214. Subject to Staff verifying the gain calculation.

S-47 Rate Spread/Rate Design: No stipulation at this time.

S-48 Residential Customers CTM/PAA/PCA, etc: No stipulation at this time.

S-49 Proposed Tariff Language Revisions, Schedules 100, 101, 108 and 115: The parties agree to certain general tariff revisions and specific language changes as described in Attachment A3.

S-50 Decoupling Adjustment, Schedule 123: No stipulation at this time.

S-51 Proposed Revisions to Schedule 48; 105, Rules B-G, I, K, and L: The parties agree to certain general tariff revisions and specific language changes as described in Attachment A4.

S-52 Tariff Schedule Review: The parties agree to certain general tariff revisions and specific language changes as described in Attachment A5.

S-53 ESS Service Agreement: No stipulation at this time. The Parties are working together to develop an ESS Service Agreement.

S-54 Reclassification of Transmission Plant: The Parties agree to the re-classification of Transmission, Distribution and Generation plant (and related operating costs) proposed in PGE's UE-115 filing, Exhibit 1500, subject to certain conditions. A separate stipulation will be developed for this issue.

Attachment A1

Cost of Capital

Portland General Electric
Composite Cost of Capital: Settlement (Excluding ROE)
Test Year Based on 12 Months Ending 12/31/02
($000)

	Average Outstanding		Percent		Percent Cost		Weighted Average Cost
Long Term Debt	$887,900		46.32%		7.508%		3.48%
Preferred Stock	$29,250		1.53%		8.432%		0.13%
Common Equity	$999,781		52.16%				
Composite Cost of Capital	$1,916,931		100.00%				

Attachment A2

Other Revenue, Operating Costs, Rate Base

Financial Summary Reflecting Stipulated Positions — Attachment A-2

Excluding Revenue Sensitive Costs

Revenue Requirement Category	FERC Wholesale Fee (S-1)	Montana Production Tax (S-2)	Colstrip O & M (S-3)	Transmission O & M (S-4)	FERC Hydro Fee (S-5)	Income Tax Apportion (S-6)	Severance Program (S-7)	OAL Sale (S-8)	PGH Billings (S-9)	Retail Unbundling Allocation (S-10)
Retail Revenues										
Other Revenue										
Production O&M			1,043		(14)			(83)		
Transmission O&M			25					(28)		
Distribution O&M								(223)		
Purchased Power										
Generation										
Wheeling										
A&G	(372)				714			108	(436)	303
Customer Service										435
Depr. & Amort.							66	100		
Other Taxes		450								
Rate Base (excluding working cash)								(439)		

Revenue Requirement Category	Beaver Turbine (S-11)	Other Revenue (S-12)	State Tax Credit (S-13)	Remove SERP Rate Base & MDCP Expense (S-14)	Remove Trojan (S-15)	Remove Neil (S-16)	Remove Other Debits & Credits (S-17)	Solar For Schools (S-18)	Salmon Springs Reclassification (S-19)	Green Power Purchase (S-20)
Retail Revenues										
Other Revenue							(589)		183	
Production O&M						2,400				
Transmission O&M										
Distribution O&M										
Purchased Power										(420)
Generation										
Wheeling										
A&G				(4,645)		1,418				
Customer Service								(55)		
Depr. & Amort.	182				(16,584)		(959)			
Other Taxes	14									
Rate Base (excluding working cash)	2,789			(2,122)	(102,904)		181			

Financial Summary Reflecting Stipulated Positions — **Attachment A-2**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	Property Tax Unbundling Correction (S-21)	Y2K Deferral (S-22)	Two Cities (S-23)	Miscellaneous Electric Revenues (S-24)	CRM (S-25)	Reduce Customer Acct. Non-Labor Exp. (S-26)	Category "A" Advertising Reduction (S-27)	Public Purpose Adjustment (S-28)	Remove Marketing & Sales Expense (S-29)	T&D O&M (S-30)
Retail Revenues										
Other Revenue				998						
Production O&M										
Transmission O&M										(1,505)
Distribution O&M										(990)
Purchased Power										
Generation										
Wheeling			129							
A&G								(149)		
Customer Service						(1,600)	(2,405)	(550)	(800)	
Depr. & Amort.										
Other Taxes										
Rate Base (excluding working cash)			96							

Revenue Requirement Category	Reduce A & G Accounts N44173 & N44174 (S-31)	Remove Suppl. Executive Retirement Plan (S-32)	Bonus & Incentive Adjustment (S-33)	Workforce Level Adjustment (S-34)	OPUC Wage Formula Adjustment (S-35)	Distribution Plant Reduction (S-36)	Materials & Supplies Adjustment (S-37)	Y2K Amortization (S-38)	NEIL Amortization (S-39)	Accumulated Deferred Taxes (S-40)
Retail Revenues						1,075				
Other Revenue										
Production O&M										
Transmission O&M										
Distribution O&M										
Purchased Power										
Generation										
Wheeling										
A&G	(1,000)	(1,250)	(2,237)	(2,411)	(1,550)					
Customer Service				(2,411)						
Depr. & Amort.						(60)		(1,977)		
Other Taxes			(240)	(518)	(167)	(30)				
Rate Base (excluding working cash)			(602)	(1,046)	(336)	(2,000)	(3,681)	(4,942)		(22,832)

Financial Summary Reflecting Stipulated Positions **Attachment A-2**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	Income Tax Adjustments (S-41)	Remove Property Sales Gains (S-42)	Depreciation Study Adj. (S-43)	SB 1149 Implementation Costs (S-44)	CIS/IT Disallowance Adjustments (S-45)
Retail Revenues					
Other Revenue					
Production O&M					
Transmission O&M					
Distribution O&M					
Purchased Power					
Generation					
Wheeling					
A&G				416	
Customer Service				376	
Depr. & Amort.		477	(3,567)		
Other Taxes					
Rate Base (excluding working cash)			1,784	459	

G:\RATECASE\OPUC\DOCKETS\UE-115\Settlement\Staff Proposal\[Stip Exhibit A2 03-07-01.xls]Adjustments

ORDER NO. 01-777

APPENDIX B
PAGE 15 OF 35

Attachment A3

ISSUE S-49: Tariff Language Changes

Schedule 100 – The Attorney General's office will review Section 43 of SB1149 and provide a written summary on how to treat special contracts that may have a provision within the contract limiting the applicability of adjustment schedules. PGE will abide by the Attorney General's summary.

Schedule 101 – All of Staff's proposed changes listed in the January 12, 2001 Staff Settlement Proposal, with the exception of adding back in the Demand Side Management Refund, will be incorporated into Schedule 101.

Schedule 108 – All of Staff's proposed changes listed in the January 12, 2001 Staff Settlement Proposal will be incorporated into Schedule 108.

Schedule 115 - The Attorney General's office will review Section 43 of SB1149 and provide a written summary on how to treat special contracts that may have a provision within the contract limiting the applicability of adjustment schedules. PGE will abide by the Attorney General's summary.

Attachment A4

S-51: Revisions to Schedule 48 and 105, Rules B-G, I, K and L.

PGE TARIFF REVIEW
PGE Exhibit 1602
Oregon E-17
Issue S-51

OVERALL STAFF COMMENT
Throughout the tariff PGE has replaced "customer" with the term "consumer". The company has defined consumer as "a person who has applied for, been accepted, and is currently receiving service." This is the definition of a "customer" per OAR 21-0008(3).

In a few places, they also replaced "applicant" with consumer which does not mean exactly the same thing. Customers have specific rights which applicants do not have.

The tariffs need to be aligned with the meanings of customer and applicant in OAR Division 21.

<u>Status</u> Resolved.
<u>Discussion</u> PGE will review for consistency and submit edits if necessary towards the end of the ratecase process for Staff review.

Schedule 48 – Standard Offer Service
Irrigation and Drainage Pumping Small Nonresidential
Added a notice under minimum charge that "...the Company may require the Consumer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities". The tariff should specify the circumstances under which the charge is incurred.

<u>Status</u> Resolved.
<u>Discussion</u> No change required to language as filed.

Schedule 105 – Property Transactions Adjustment - Property is spelled "propery" in the title

<u>Status</u> Resolved.
<u>Discussion</u> Will be corrected.

Rule B – Definitions
Applicant – "A person or business applying to the Company for Electricity Service or reapplying for service at a new or existing location after service has been discontinued *for greater than 20 days*." This tariff is not in compliance with OAR 21-0008(1). It mixes up a customer's right to retain customer status for twenty days after a voluntary disconnect with the definition of an applicant. A customer becomes an applicant automatically if service is involuntarily disconnected.

Status	Resolved.
Discussion	'for greater than 20 days' - phrase will be stricken.

Rule B – Definitions
Customer Service Charge – deleted, should be included.

Status	Resolved.
Discussion	Customer Service Charge-This term is eliminated. Basic Charge - Definition will be added. Energy Charge - Definition will be added. Demand Charge - Definition will be added. Reactive Demand Charge- Definition will be added.

Rule B – Definitions
Premises – deleted the section regarding the circumstances under which various types of business properties are considered one premises. If there has been no change in intent, the deleted portion should be restored.

Status	Resolved.
Discussion	Definition of SITE added (as written in AR-390 Order 01-073 entered Jan 3, 2001). PGE will review use of the term "premise" versus "site" towards end of the ratecase process for Staff review.

Rule B – Definitions
- Kilovar – deleted, should be included.
- Kilowatt – deleted, should be included
- Kilowatt Hour – deleted, should be included

Status	Resolved.
Discussion	All three definitions will be added back.

Rule B – Definitions
Irrigation Service – deleted, should be included

Status	Resolved.
Discussion	This will be left out as this statement is included in the individual schedules in E-17, and which irrigation customers qualify for the RPA credit is defined under Schedule 102 in E-17.

Rule B – Definitions

Residential Consumer – deleted the reference to 30-days for transient occupancy, deleted the description of a dwelling, and the caveat that a recreational vehicle is not a dwelling. Deleted the section regarding multi-family dwellings. Verbiage in the current tariff regarding the definition of a dwelling, recreational vehicles, and multi-family dwellings was the result of several different complaints handled by Consumer Services. It should be retained in order to maintain the clarity of the tariff.

Status Resolved.

Discussion
- Definition for "Residential Consumer" will be modified to include descriptions of the terms transient occupancy, dwelling, and multi-family.
- Definition of "Transient Occupancy" will be added to Rule B. (30 day limitation is included).
- Recreational Vehicles qualify for residential service as per SB1149.

Rule B – Definitions

Transient Occupancy – deleted. Transient occupancy is referred to in the definition of residential service, the definition should be included.

Status Resolved.
Discussion Definition returned.

Rule C – Conditions Governing Consumer Attachment to Facilities

C-8 Hazardous Substances – deleted term "applicant" throughout. Because "consumer" does not have the same meaning, applicant should be restored where applicable.

Status Resolved.
Discussion Restored where applicable.

Rule C – Conditions Governing Consumer Attachment to Facilities

C-14 Service Restoration is an entirely new section putting into the tariff the restoration priorities. It states "The Company will not give priority to any Consumer or ESS but will employ the above process over the Company's entire territory served." Is this a change from the policy that allowed identification of medically needy accounts for restoration purposes?

Status Resolved.
Discussion No editing required.

Rule D – Consumer Service Requirements

D-1 allows applications to be accepted from **third-parties** such as landlords. This is not within current accepted procedures. Only the person intending to be the customer of record can obligate themselves to paying for service.

Status Resolved.
Discussion PGE will revise wording so this option is available but the implication that this is a common situation for landlords will be removed.

Rule D – Consumer Service Requirements
D-4 leaves out the term "same type of utility service" (OAR 21-0200) under deposit requirements and letter of credit option. It should be restored to be in line with Division 21.

Status Resolved.
Discussion Wording added.

Rule D – Consumer Service Requirements
D-5 states a notice shall be mailed six business days before disconnection. "No less than" should be added to avoid a problem with disconnects occurring past six days.

Status Resolved.
Discussion Wording added.

Rule D – Consumer Service Requirements
D-5 deleted the part about customers on a Time Payment Agreement who default on deposit arrangements (OAR 21-0205(7). Needs to be added.

Status Resolved.
Discussion Added sentence and OAR reference.

Rule D – Consumer Service Requirements
D-6 adds a new section "Like Occupancy" – "When a Residential Applicant requests Electricity Service and the previous occupant(s) of the dwelling continues to reside at the dwelling, the Applicant will be considered a co-Consumer and may be required to pay a deposit." This does not comply with OAR 21-335 (Refusal of Service Rule) or 21-200 (Establishment of Service).

Status Resolved.
Discussion Deleted.

Rule D – Consumer Service Requirements
D-7 nonresidential deposit requirements added a consumer who "has had their Electricity Service discontinued by an ESS for nonpayment of charges." Consumer Services is concerned about basing deposits for regulated services on credit history with an unregulated company.

Status Resolved.
Discussion PGE will insert the following language instead: The Company reserves the right to check an applicant's credit and, based on the credit report, a deposit may be requested.

Rule D – Consumer Service Requirements
D-9 added that credit is established one year after a deposit or final deposit installment is paid. OAR 21-215 only uses the term "one year after a deposit is made. It doesn't mention installments. So this means that a customer who makes installment arrangements does not establish credit for fourteen months.

Status Resolved.
Discussion Language removed.

Rule E – Billings
E-1 Continuing Nature of Charges – "Disconnect and reconnect transactions do not relieve a Consumer from the obligation to pay charges that accumulate during the periods where the Company makes Electricity Service available but such service is not used by the Consumer." The charges in question need to be clearly identified.

Status Resolved.
Discussion PGE added the word 'Basic' so it now reads: "... do not relieve a Consumer from the obligation to pay Basic or Minimum Charges that accumulate....

Rule E – Billings
E-2 Responsibility for Payment deleted the option for closure of an account by a landlord. This could impact the ability of a new tenant to put service in their name if the outgoing tenant has not closed their account.

Status Resolved.
Discussion New language added: "The Company may accept a change of occupancy notification from a third party. The Company may refuse to process a change of occupancy until it receives satisfactory evidence of the third party's authority to request such a change."

Rule E – Billings
E-3 Assessed Demand deleted two sentences from the current tariff: "Demand will be billed to the nearest whole kilowatt, and Reactive Demand will be billed to the nearest whole kilovar. At the Company's option, Demand may be determined by test or assessment." The material deleted clarifies the tariff.

Status Resolved.
Discussion Word "whole" included in Rule B definitions.

Rule E – Billings
E-4 Special Meter Reading deleted the allowance for one special read in twelve months at no charge. The charge is now $24 for each special read that does not result in a billing correction.

Status Resolved.
Discussion Clarifying language added: "The first special read is free if the purpose is to verify a previous read but that if the special read is associated with movement to open access, the one free read does not apply."

Rule E – Billings
E-4 Unmetered Loads deleted the description of how estimated monthly usage is calculated (1/12 of the annual use determined by the Company by test or estimated from equipment ratings).

Status Resolved.
Discussion No change required. This change is okay based on the need to not use 1/12 for some consumers that may go direct access.

Rule E – Billings
E-5 Payment of bills changes the calculation for prorated bills from multiplying the number of days in the period and dividing by 30.4167 to 30 (except for Consumers billed by the legacy system).

Status Resolved.
Discussion No change required.

Rule F – Disconnection and Reconnection
F-1 Deletes all references to the OAR which were in the previous tariff.

Status Resolved.
Discussion OAR cites returned.

Rule F – Disconnection and Reconnection
F-1 Grounds for Disconnection leaves out "Oregon" in "For failure to pay Company Tariff charges..." (OAR 21-0305(5))

Status Resolved.
Discussion The word "Oregon" is returned.

Rule F – Disconnection and Reconnection
F-2 Adds section "A Consumer who has avoided disconnection of Electricity Service by making a non-cash payment that is subsequently returned by the Consumer's financial institution is subject to disconnection of such service. Prior to disconnection the Company must make a documented good faith attempt to notify the Consumer of the returned payment and that service will be disconnected without further notice if payment is not received within one business day. When remitting for dishonored funds the Consumer shall make the payment in either cash, money order, cashier's check or verified credit card payment.

- Consumer Services suggests changing to "A Consumer who has avoided disconnection, *established credit, or gained reconnection* of Electricity Service..."
- Also, add a section under credit establishment to clarify that an Applicant who establishes credit or pays an outstanding bill from a prior account by making a non-cash payment which is returned does not obtain customer status. They would still come under the one-day notice but it would make it clear they are NOT customers with the right to a TPA or medical certificate option.

Status	Resolved.
Discussion	Language change will be reviewed with Staff.

Rule G – Line Extensions
G-1 Purpose does not include Applicant in the list of folks who may request a line extension.

Status	Resolved.
Discussion	Researching editing possibilities as Applicant has a different meaning in Rule G. Language changes will be reviewed with Staff.

Rule G – Line Extensions
G-1 Does not include Applicant as being represented by an agent.

Status	Resolved.
Discussion	Researching editing possibilities as Applicant has a different meaning in Rule G. Language changes will be reviewed with Staff.

Rule G – Line Extensions
G-2 Line extension cost omitted "labor" from the list of costs.

Status	Resolved.
Discussion	The word "labor" is returned.

Rule G – Line Extensions
G-9 Deleted the section on Unity installations

<u>Status</u> Resolved.
<u>Discussion</u> Unity is now described on Sheet G-4. No action required.

Rule G – Line Extensions
G-9 • Adds a section on "Service Locates" which states that there is a charge to locate underground utility services on private property along the Applicant's proposed trench route"

- Add the clarification this applies only to subdivision (per Schedule 300)
- How does this relate to One-Call?

<u>Status</u> Resolved.
<u>Discussion</u> PGE is researching clarifying language which will be reviewed with Staff.

Rule I – Metering
I-3 Nonstandard Metering deletes the option for customers to choose nonstandard metering, now limits the request to ESS.

<u>Status</u> Resolved.
<u>Discussion</u> No change required. Customers still have the right to other meters. It is discussed under Interval Metering on the same sheet.

Rule I – Metering
I-4 Inaccessible Meters states that the company may *in its sole discretion* permit the Consumer to read the meter. The tariff does not comply with OAR 21-120(3)(a) which states ..."the energy utility shall seek the customer's cooperation in obtaining monthly readings (for example, having the customer complete and return a meter reading form).

<u>Status</u> Resolved.
<u>Discussion</u> The words 'in its sole discretion' are removed.

Rule K – Curtailment Plan

K-2 Curtailment Target deleted the calculations.
K-5 Stage 3 Notification deleted "Who will be audited... and who request" from "Provide Curtailment Targets to ESSs and Consumer. It also deleted a paragraph about providing information regarding exemption and processing requests for exemption.
K-6 Identification of the Base Year deleted "weather-normalized".
K-6 Estimating Base Billing...Changed audited customers with an option to exclude residential and small use to "all Consumers".
K-7 Communicating Curtailment Target Information deleted reference to retroactive information for audited customers.
K-8 Threshold Consumption Level deleted reference to changes required by the state.
K-8 Excess Electricity Calculation deleted how the excess load is calculated.
K-9 Non-Financial Penalties deletes references to sampling and substantially changed the penalty options.
K-10 Application for Exemption deletes reference to audited customers.
K-10 Granting Requests for Exemption deletes a paragraph with options to provide credit against further curtailment and the statement advising customers exemptions may not protect them against stage 5 curtailment.

Status	Resolved.
Discussion	E-17 Rule K language changes have been replaced with existing E-16 Rule M Curtailment Plan language.

Rule K – Curtailment Plan

K-2 General Use Consumer shows 43,800 MWh. Previous tariff had 48,300. Major Use Consumer had 43,800 in old (and new). Verify which was in error.

Status	Resolved.
Discussion	Corrected. Proposed E-17 now reads 43,800.

Rule L – Special Types of Electricity Service

L-1 Availability changed Applicant to Consumer (they do not have the same meaning).

Status	Resolved.
Discussion	It now reads, "Where Facilities other than those specified above are needed to provide service, the provisions of Rule G, Line Extensions, will apply."

Attachment A5

S-52: Tariff Schedule Review

Tariff Language Changes to
PGE Exhibit 1602
Oregon E-17
Issue S-52

The following review is broken into two parts, "A" and "B." Staff contacts for part A are Jack Breen. Deborah Garcia, and Rebecca Hathhorn. The staff contact for Part B is Stefan Brown.

Part A

RATE SCHEDULES

Schedule 7 – Residential Service

Portfolio Option Enrollment

- The language for portfolio option enrollment is subject to the decisions of the Advisory Committee as approved by the Commission.

STATUS	RESOLVED.
DISCUSSION	The language will be revised based upon Advisory Committee recommendation.

Schedule 82 – Emergency Default Service Nonresidential

- Availability

STATUS	Not stipulated.

Direct Access Schedules – 500 series

ESS Charges

- The last sentence states, "...the Company's charge for Direct Access Service may not be separately stated on the bill." In Data response No. 171, PGE intends to use alternative wording "The Company charges for Direct Access Service are not required to be separately stated on an ESS consolidated bill."

STATUS	RESOLVED.
DISCUSSION	The alternative wording in Data Response #171 will be used.

Schedule 300 – Miscellaneous Charges
Interest accrued on Consumer Deposits

- The rate is now 6%. The tariff will need to be modified accordingly. Additionally, the title should delete "Consumer" to clarify that deposit interest applies to an ESS deposit, as well as a consumer deposit.

STATUS RESOLVED.
DISCUSSION Staff changes adopted.

Schedule 600 – Energy Service Supplier Charges
ESS Support Services

- Maintenance Fee

STATUS Not stipulated.

Schedules 7, 15, 32, 38, 48, 49, and 86
Term

- Staff questions the justification of the requirement of a one-year term for service under these schedules. In Data response No. 174, PGE states it will further consider the issue and may provide revised term provisions at a later date.

STATUS RESOLVED.
DISCUSSION Term requirements were removed from Schedule 7 (unless required by a Portfolio Option) and set at 1 year for 15, 32, 38, 48, 49, and 86.

Schedules 83, 91, 92, 93, and 97
Term

- Staff questions the justification of the requirement of a five-year term for service under these schedules. In Data response No. 175, PGE states it will further consider the issue and may provide revised term provisions at a later date.

STATUS RESOLVED.
DISCUSSION Term requirements were removed from Schedule 83 (unless required by a pricing option) and set at 1 year for 91, 92, 93, and 97.

RULES

Rule C – Conditions Governing Consumer Attachment to Facilities
Sheet C-3 C. Limitation on Damages

STATUS Not stipulated

Sheet C-14 Service Restoration

- A. PGE should add language similar to: "Restoration priority is independent of whether a consumer purchases supply services from the Company or its affiliates, or from an ESS."

STATUS RESOLVED.
DISCUSSION PGE agrees. The following language is located on last page of Rule C:

> "The Company will not give priority restoration to any Consumer or ESS, but will employ the above process over the Company's entire territory served."

Rule D – Consumer Service Requirements
Sheet D-6 Deposit Requirement

- Staff believes the credit-screening criteria language of B.(2) should be modified to correspond to the establishment of credit language in Sheet D-9 Treatment of Deposits A.(2)

STATUS RESOLVED.
DISCUSSION The revision will be made on Sheet D-6 at 4B(2)

Sheet D-7 Nonresidential Credit Standards

- (6) Staff believes the nonresidential deposit requirement in (6) should be deleted. A consumer who has had their Electricity Service discontinued by an ESS for nonpayment of charges may have a legitimate dispute. and the consumer's nonpayment to the ESS should not be the sole basis for a deposit request. PGE may consider nonpayment to an ESS as it would any other nonpayment to a creditor within the context of a credit report. In Data Response 202, PGE reaffirmed that it intends to require a deposit from a consumer who had electricity disconnected by an ESS for nonpayment.

STATUS RESOLVED.
DISCUSSION The disputed language was deleted. The following was added to the credit screening requirements:

> "The Company reserves the right to check an Applicant's credit and, based on the credit report, a deposit may be requested."

Rule E – Billings
Sheet E-11 ESS Billing Responsibilities

- 24-hour turnaround for ESS

STATUS Not stipulated.

Rule F – Disconnection and Reconnection
Sheet F-3 – Disconnection and Reconnection Charges

- A. In the last sentence, "reconnection" should be changed to "disconnection". "Should this require a second trip to the premises to perform the ~~reconnection~~ disconnection the charge for reconnects at Other Than the Meter Base...." In Data response No. 207, PGE agreed to correct the error.

STATUS RESOLVED.
DISCUSSION Error corrected.

Rule G – Line Extensions
Sheet G-5 (d)

- Delete "All costs incurred by the Company shall be included as Line Extension Costs."

STATUS RESOLVED.
DISCUSSION This sentence will be moved and modified such that it is clear that customers building their own lines will be charged based on estimated actuals. Wording may fit better on Sheet G-2.

Sheet G-6 Applicants for New Permanent Service

- The language in existing tariffs should be retained.

STATUS RESOLVED.
DISCUSSION Add wording under the "Other Than Individual Applicants" section that clarifies residential subdivision refunds are not based on expected load.

Sheet G-14 Nonpermanent Line Extension

- The section deletes the payment of interest on money paid for a nonpermanent extension that becomes permanent. Why?

STATUS RESOLVED.
DISCUSSION PGE will pay interest.

Rule H – Requirements Relating to ESSs

Sheet H-1 & H-2 Service Agreement

- See settlement package work papers for line S-53. Staff suggests a workshop be held to discuss the content of a service agreement.

STATUS Being considered under S-53.

Sheet H-2 Credit Requirements and Security

- Delete "or more" from the last sentence of the first paragraph.
- (2) Staff is concerned about PGE exercising discretion in the credit evaluation process. The criteria should be explicitly identified in the tariff or standard service agreement, rather than being applied on a case-by-case basis.
- 3 (b) PGE should add "equal to 90 days of business volume" to the first sentence after "A letter of credit ...."

STATUS Being considered under S-53.

Sheet H-3 Default of ESS Service Agreement

- Staff believes the customer must be notified as soon as possible of the switch to emergency default service. A provision for notification should be added.

STATUS RESOLVED.
DISCUSSION Suggestion is adopted.

Sheet H-3 Information and Credit Updates

- See Staff's discussion under H-2 Credit Requirements and Security.

STATUS Being considered under S-53.

Sheet H-5 Electronic Data Transfer

- Staff believes the first paragraph should be changed so that the ESS is required to notify the Company only if it plans to modify its electronic data interchange systems if it will affect the form or content of the information. In the last sentence, "may" should be changed to "will."

STATUS RESOLVED.
DISCUSSION Suggestion is adopted.

Sheet H-6 Criteria for Recommending Decertification

- (12) "...or should have known..." should be stricken from the tariff.

STATUS RESOLVED.
DISCUSSION Suggestion is adopted.

Sheet H-8 Refusal of DASR

- 1. Staff believes this should be deleted. Acceptance of a DASR does not necessarily mean that a consumer will receive service. For example, if the consumer does not pay regulated charges, service can be disconnected.

STATUS Being considered under S-53.

Sheet H-8 Refusal of DASR (continued)

- 2. Staff believes this should be deleted. The Company cannot hold a customer responsible for ESS obligations.

STATUS Being considered under S-53

Sheet H-8 Refusal of DASR (continued)

- 4. Staff recommends this be deleted.

STATUS Being considered under S-53.

Sheet H-8 Refusal of DASR (continued)

- 5. Standard offer term obligations are in question.

STATUS RESOLVED.
DISCUSSION Staff's changes adopted.

Sheet H-8 Refusal of DASR (continued)

- 6. Staff recommends this replacement: "The ESS is not certified by the Commission."

STATUS Being considered under S-53.

Sheet H-8 Refusal of DASR (continued)

- 7. This should be deleted. The issue of full payment from the ESS for charges assessed to the ESS should be addressed in disconnection of an ESS within the tariff or service agreement.

STATUS Being considered under S-53.

Sheet H-9 Return of Consumer Deposits

- Staff suggests that the last sentence be modified so that it is clear that the Company is holding a deposit for regulated services only.

STATUS RESOLVED.
DISCUSSION Staff changes adopted.

Sheet H-10 Company Billings to the ESS

- Remove requirement for electronic payment, unless there is a reciprocal agreement between the Company and the ESS. Change due and payable period from five to fifteen days in accordance with OAR 860-021-0125.

STATUS RESOLVED.
DISCUSSION Changed to 15 days.

Sheet H-12 Company Scheduling Responsibilities
B. Major Outage Procedures

- Should add statement that Company intends to negotiate reductions in energy scheduling in a nondiscriminatory fashion.

STATUS RESOLVED.
DISCUSSION Staff's alternate wording is adopted:

> "The Company may require an ESS to reduce its Electricity Schedule in the event of a major loss of load due to a major outage consistent with the Company's resources."

Sheet H-16 Dispute Resolution

- The dispute resolution process should be consistent for all ESSs, not a function of the individually negotiated terms and conditions of a service agreement.

STATUS Being considered under S-53.

Rule I – Metering

Sheet I-2 Meter Verification Fee

The last sentence should be changed to reflect the current tariff. "...the Company will waive the Meter Verification fees..." rather than "may."

STATUS RESOLVED.
DISCUSSION Staff changes adopted.

Sheet I-3 Interval Metering

- 45 days is too long for a meter installation. In addition, the customer is prohibited from purchasing electricity from the ESS for that period.

STATUS RESOLVED.
DISCUSSION 45 days changed to 30 days.

^^^

Part B

Rule K – Curtailment Plan

The Company withdraws its proposed changes to Rule K (Rule M in current E-16 tariff) with the exception of the correction to the MWh number.

STATUS RESOLVED.
DISCUSSION PGE withdraws its proposed changes to Rule K (Rule M in current E-16 tariff) with the exception of the correction to the MWh number.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	))))	STIPULATION WITH CITY OF PORTLAND AND LEAGUE OF OREGON CITIES

This Stipulation is entered into for the purpose of resolving specific issues identified by the City of Portland (City) and the League of Oregon Cities (League) in their Opening Testimony filed March 12, 2001. This Stipulation presents a full settlement of the detailed issues.

I. INTRODUCTION

On October 2, 2000, Portland General Electric Company (PGE) filed Advice No. 00-14 proposing certain increases in its base prices to its customers. The filing was based on a projected test year of 2002 and included tariffs changing rates paid by the City and members of the League. Advice No. 00-14 was suspended by the Commission at its October 20, 2000 Public Meeting, Order No. 00-669.

The Administrative Law Judge issued a Ruling on March 12, 2001, requiring, among other things, that the City and the League enter into settlement talks with PGE. A Settlement Conference, which was open to all parties, was held on April 23, 2001.

As a result of that settlement conference, the parties signing this Stipulation (Parties) have agreed to specific adjustments in PGE's requested tariff and rate proposals. The Parties submit this Stipulation to the Commission and request that the Commission approve the settlement as presented.

II. GENERAL TERMS OF STIPULATION

1. The Parties to this Stipulation agree that PGE will adjust its proposed tariffs and rate proposals to reflect the agreements detailed in this Stipulation.
2. The Parties recommend that the Commission approve the various tariff, rule, and other adjustments described in this Stipulation.
3. The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements, and documents disclosed in the negotiations of this Stipulation shall not be admissible as evidence in this or any other proceeding.

4. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained in it.

5. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks changes in PGE's tariffs that depart from the terms of this Stipulation, the Parties to this Stipulation reserve the right to cross-examine witnesses and introduce evidence 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 Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

6. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving this Stipulation, any Party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's order.

7. By entering into the Stipulation, no Party shall be considered 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. No Party shall be considered to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

8. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

III. SPECIFICALLY STIPULATED ADJUSTMENTS

For issues raised by the City and the League regarding PGE's proposed tariffs, rules, and rates, the Parties agree as follows:

9. With regard to Interconnection Standards, PGE publishes interconnection standards as part of its avoided cost filing based on the most current version of IEEE published standards. These standards apply whether or not a generating unit qualifies as a QF under State and Federal law, and whether or not a particular generating technology is identified in such laws. An interconnection at transmission level or one that affects the transmission system is also subject to the interconnection provisions of PGE's Open Access Transmission Tariff. PGE agrees that its interconnection standards will continue to reference applicable IEEE criteria, and that implementation of such standards will follow such IEEE criteria. If the City or another member of the League opts to pursue this course, PGE will work cooperatively with that municipality as necessary if the municipality chooses to apply for Exempt Wholesale Generator (EWG) or similar status at the Federal Energy Regulatory Commission.

10. With regard to Restoration of Utility Services, PGE will propose to rewrite part of Rule

C. In addition to other clarifying changes, the language in the currently proposed Part (7)(B)(2) will be rewritten to read: "The Company will first make the necessary repairs to transmission lines, substations, and distribution facilities that connect substations to critical load Consumers. Then the Company will continue to repair remaining transmission lines and substations after critical load Consumers have been restored to service." In addition, PGE agrees that it will continue to work cooperatively with municipalities and other public bodies to identify such critical load Consumers or accounts.

11. With regard to the Definition of a Large Non-Residential Consumer, the City and the League understand that PGE's definition will result in automatic reclassifications if the Consumer's usage varies, as determined by the classification standards approved by the Commission and reflected in PGE's Tariff.

12. With regard to Utility Relocation, PGE will propose to rewrite Part 6(b)(1) of Rule C to read: "The rearrangement can be identified to be a public works project. Examples of public works projects include but are not limited to public transit and a road widening financed by public funds."

13. With regard to the Allocation of Ancillary Service Costs, the City and the League accept the proposal in PGE Exhibit 2402.

14. With regard to Streetlights, the City, the League, and PGE agree as follows:

a. With regard to Luminaire/Circuit charges, PGE will withdraw the proposed revisions identified in its October, 2000 filing. Specifically, PGE will eliminate that component of the distribution charge for Schedule 91 service that recovers the marginal cost of service drops (identified as $1.139 million in PGE's October 2000 filing, Exhibit 1603 at 12). The existing Luminaire/Circuit charges contained in the Streetlight Agreement between PGE and the City dated May 1, 1997, will remain in place without modification and will apply to all Schedule 91 accounts. These charges are as follows:

Option A lights will be charged $0.64/month/light.

Option B lights will be charged $0.64/month/light.

Option C lights will be exempt from the circuit charge.

Option C circuits will be charged $0.64/month/circuit consistent with the Streetlight Agreement between PGE and the City dated May 1, 1997, and current Schedule 91.

b. With regard to Group Relamping, PGE will charge for group relamping services at an effective rate of 19% per year, (or 95% over five years), while continuing to provide services at a level of relamping 20% of all streetlights per year (or 100% over a five year period).

c. With regard to Power Doors Luminaires, PGE will use a maintenance level of 175 per year for power door usage, which translates into a frequency of 0.47%.

d. With regard to Pole Replacement, PGE will use a replacement frequency of 0.25% for calculation of all rates and charges.

15. The City and the League agree that, except for the issues specifically noted below, all other issues addressed in their direct testimony will not be pursued in this docket but may be addressed in other proceedings:

a. Allocation of the CTM credit among customer classes;

b. Minimum duration of ESS purchase of transmission service;

c. Portfolio Enrollment and Switching Fees (Schedule 300); and,

d. Aggregation of accounts through metering (Rule E).

This Stipulation is entered into by each Party on the date entered below.

Dated this 6 day of June, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

CITY OF PORTLAND

By: Benjamin Walters

LEAGUE OF OREGON CITIES

By: ______________________

STAFF OF THE OREGON PUBLIC UTILITY COMMISSION

By: ______________________

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149

STIPULATION CONCERNING POWER COSTS

This Stipulation is among Portland General Electric Company (PGE), Staff of the Public Utility Commission of Oregon (Staff), Fred Meyer Stores, the Industrial Customers of Northwest Utilities (ICNU), the Citizens' Utility Board (CUB) and any other parties signing this Stipulation (collectively, the Parties).

The Parties have been active participants in this docket. As part of that participation, PGE has filed proposed tariffs, and PGE and other Parties have filed testimony and exhibits addressing PGE's proposals to establish power costs in this docket, PGE's proposal to value its Long-Term Resources, PGE's proposal to value its Short-Term Resources, PGE's proposal to adjust rates to account for changes in power costs and Energy Revenues from those used to establish base rates in this docket, and proposals made by other Parties. Capitalized terms used in this Stipulation have the meanings ascribed to them in this Stipulation or the attached tariff schedules.

The Parties held settlement conferences on these matters on May 24, May 25, June 1, June 12, June 28, July 11, and July 16, 2001. As a result of those settlement discussions, the Parties have negotiated this Stipulation to accomplish the following:

(a) To establish the mechanism by which PGE will value its Long-Term and Short-Term Resources for the purpose of establishing rates for energy services in this docket;

(b) To account for the current hydro and market conditions affecting PGE. The Parties intend to reflect in Part C of Schedule 125 the difference in PGE's projected NVPC between such costs under expected hydro and market conditions (Expected NVPC), and such costs under the normal hydro conditions ordinarily used to established rates (Base NVPC). In general, this adjustment accounts for the current low reservoir levels and their effect on future power costs, but assumes normal weather on a going-forward basis;

(c) To establish the mechanism by which PGE will account for variations in its actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues used to establish PGE's energy prices in this docket, and the method by which PGE and its customers will share in the benefits and burdens of such variations;

(d) To establish the method and date upon which PGE's Expected NVPC, Base NVPC and Base Energy Revenues will be calculated; and

(e) To establish a Shopping Incentive for large non-residential customers who use less than 1000 kWa.

The Parties agree to and request that the Commission adopt orders in this docket as follows:

1. PGE's Long-Term Resources and Short-Term Resources shall be valued under the mechanism described in Schedule 125. The Commission shall adopt Schedule 125 (attached to this Stipulation as Exhibit A) in its entirety for purposes of this docket.

2. The effect of adverse hydro conditions on PGE's projected NVPC shall be taken into account under Part C of Schedule 125. The Part C costs and revenues shall be a part of actual NVPC and actual Energy Revenues under Schedule 127. The Parties recognize that Part C expires December 31, 2002. The Part C adjustment shall be based on reduced hydro generation from that available in the water year used to develop normalized power costs of 300,000 MWh over the period October 2001 through December 2002 which shall be allocated to months based on Exhibit E attached to this Stipulation.

3. Schedule 127 shall be used to calculate the variances in PGE's actual NVPC from Base NVPC and actual Energy Revenues from Base Energy Revenues used to establish rates in this docket for the period ending December 31, 2002, and for the purpose of sharing the benefits

and burdens of such variances between PGE and its customers. Schedule 127 shall not apply to Schedule 83 customers unless they elect the Annual Fixed Price Option. The Commission shall adopt Schedule 127 (attached to this Stipulation as Exhibit B) in its entirety for purposes of this docket. The Parties recognize that PGE will collect or refund through the Power Cost Adjustment Rate only the Adjustment Amount for the period October 2001 through December 2002.

4. The Parties agree that the mechanisms provided in Schedules 125 and 127 fairly balance the interests of customers and PGE with respect to variations in PGE's actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues used to establish rates in this proceeding and the effect that such variations will have upon the earnings of PGE for the period ending December 31, 2002. Accordingly, the Parties agree and request that:

(a) To the extent that a deferral of revenues or costs is necessary to implement the mechanism provided in Schedule 127, the Commission, at the request of PGE or any other Party, shall defer the variation in actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues used to establish rates in this docket. The Parties will not oppose any such deferral application and will support any such deferral consistent with this stipulation;

(b) The Parties shall request that the Commission allow PGE to amortize into rates, both before and after December 31, 2002, that portion of the variation in actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues that is the Adjustment Amount produced by the application of Schedule 127, notwithstanding the results of any earnings review that the Commission may be required to conduct under ORS 757.259. In any such earnings review, the Parties shall support full recovery or refund of the Adjustment Amount without any adjustment, except those adjustments specifically allowed in this Stipulation.

(c) The Parties agree to support recovery or refund of the Adjustment Amount in any proceeding to amortize such Adjustment Amount into rates or to implement Schedule 127.

(d) Any balance in the Power Cost Adjustment Account under Schedule 127 will begin to accrue interest on and after January 1, 2003. In addition, there shall be added to the balance at January 1, 2003, an amount equal to the product obtained by multiplying one-half of the balance at December 31, 2002, by an interest rate equal to 15 months of PGE's last approved Cost of Capital.

5. (a) PGE will estimate the difference between what the Boise Cascade St. Helens Plant (Boise) is projected to pay under actual rates for the three-month period October 2001 through December 2001 and what Boise is projected to pay on standard rates. This difference will be credited to all customers with interest at PGE's cost of capital as a separate kWh credit over the 15-month period October 1, 2001, through December 31, 2002, under the Special Contract Adjustment Schedule 131 (attached to this Stipulation as Exhibit C). The Commission shall adopt Schedule 131 in its entirety for purposes of this docket. This credit will be included as an offset to actual Energy Revenues under Schedule 127.

(b) For purposes of determining Base Energy Revenues for Schedule 127, PGE will assume that Boise is on standard rates for the entire period of October 2001 through December 2002.

(c) For purposes of determining actual Energy Revenues for Schedule 127 for Boise for the October 2001 through December 2001 period, the following shall be summed:

- Energy Revenues as if Boise was billed under standard rates, and
- The difference between actual bills to Boise and bills calculated as if Boise was under standard rates.

6. PGE shall establish its Expected NVPC and Base NVPC for purposes of this docket by running its Monet Power Cost Model on or about September 11, 2001, or such later date as may be determined by the Commission.

7. PGE shall remove $100,000 in administrative and general costs from its revenue requirement used to set rates to reflect costs included in its revenue requirement related to its

demand exchange program. This adjustment reflects the uncertainty that demand exchanges will occur under Schedule 86, PGE's demand exchange tariff. For any month beginning October 2001 and ending December 2002 in which PGE and a customer participate in a demand exchange under Schedule 86, PGE shall add $8,333 to its actual NVPC for purposes of Schedule 127. This will allow PGE to recognize costs of the demand exchange when and if demand exchanges occur.

8. The Parties recognize that PGE's power cost situation is unique, given its exposure to the wholesale energy market in order to serve its retail customers and the current uncertainty and volatility in the wholesale energy market. Accordingly, this Stipulation represents a settlement in compromise of the positions of the Parties with respect to the matters contemplated by this Stipulation in light of the unique circumstances of PGE and the wholesale market energy market. This Stipulation may not be cited or used as precedent by any party or person in any proceeding except for those proceedings implementing the terms of this Stipulation.

9. For the purpose of allocating total fixed and variable power costs among PGE's customer classes and calculating Parts A and B of Schedule 125, the Parties agree that PGE shall allocate its Long-Term and Short-Term Resources and market purchases as follows:

(a) First, PGE shall allocate its Long-Term Resources (including a credit for any PGE provided ancillary services) among customer classes in proportion to their respective percentages of PGE's expected retail load (adjusted to remove the effects of any demand exchanges) for the 12 months ended September 30, 2001;

(b) Second, Subscription Power from the Bonneville Power Administration shall be allocated to the residential and small-farm customers of PGE eligible to participate in BPA's Residential Exchange Program;

(c) Third, PGE shall allocate its Short-Term Resources among all customer classes until each customer class has been allocated a sufficient amount of Long-Term

Resources, BPA Subscription Power and Short-Term Resources to cover the expected load of that class; except that, to the extent that the resources available under paragraphs (a), (b) and this paragraph (c) are insufficient to serve all expected customer load, PGE shall allocate such shortfall among the customer classes in proportion to their respective percentages of expected shortfall. Any shortfall of resources for any customer class shall be filled by market purchases; and

(d) Any excess of Short-Term Resources over expected load shall be allocated among all customer classes in proportion to their respective percentages of expected load.

(e) If, after applying (a) and (b) above, the residential class has sufficient resources to meet expected load, Short-Term Resources shall be allocated to the other classes on a pro rata basis until they reach the same relative position as the residential class. Any remaining Short-Term Resources shall then be allocated in accordance with (d) above.

10. The Parties agree to support Schedule 130, Shopping Incentive for large non-residential customers below 1MWa described in Exhibit D attached to this Stipulation. The Commission shall adopt Schedule 130 in its entirety for purposes of this docket.

11. ICNU and Fred Meyer Stores will not argue in this docket that the residential and small farm customer classes should be assigned additional costs of load shaping and load following related to BPA Subscription Power allocated to the residential and small farm customer classes.

12. The Parties agree that, so long as PGE does not file a general rate case for rates to become effective prior to December 31, 2002, they will not advocate or support, for rates effective prior to January 1, 2003, an adjustment to PGE's estimated or projected NVPC similar to the adjustment which the Staff sought to introduce into evidence in the proposed surrebuttal testimony of Staff Witness Bill Wordley in this docket, which testimony was disallowed by the Administrative Law Judge. The Parties also agree that, except as otherwise provided in this Stipulation, they are not bound by the terms of this Stipulation in any future general rate

proceeding initiated by or against PGE.

13. The Parties agree and support the conclusion that Paragraphs 9 and 11 of this Stipulation and Schedule 125 are designed to ensure that 100% of any federal system benefits provided by BPA to PGE, on behalf of its residential and small farm consumers, will flow through to such consumers.

14. The Parties agree to support this Stipulation before the Commission and before any court in which this Stipulation may be considered. 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 rejecting this Stipulation or adding such material condition.

15. Upon written request, PGE shall make available to any Party to this Stipulation, within 10 business days, all data and workpapers that support the calculations required under the Schedules attached hereto.

16. The Parties shall file this Stipulation with the Commission.

17. 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 only one agreement.

18. The parties to any dispute concerning this Stipulation agree to confer and make a good faith effort to resolve such dispute prior to bringing an action or complaint to the Commission or any court with respect to such dispute.

19. The parties agree that the combination of PGE's Standard Offer tariff schedules and the Schedule 125 Resource Valuation Mechanism provides cost-of-service options to customers eligible to receive service under such schedules.

20. The parties acknowledge that legislation has delayed the date for direct access under SB 1149 and that Administrative Law Judge Grant has issued a Post-Hearing Conference

Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this 27th day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

FRED MEYER STORES

By: ______________________

INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES

By: ______________________

CITIZENS' UTILITY BOARD

By: ______________________

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Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this _____ day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
By: ______________________	By: ______________________
FRED MEYER STORES	INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES
By: Michael L. Kurtz	By: ______________________
Michael L. Kurtz, Esq.	

Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this _______ day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
By: ____________________	By: ____________________
FRED MEYER STORES	INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES
By: ____________________	By: ____________________

CITIZENS' UTILITY BOARD

By: ____________________

Robert T. Jenks

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Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this 27th day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: David B. Hatton

FRED MEYER STORES

By: ______________________________

INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES

By: ______________________________

Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this _____ day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
By: ______________________	By: ______________________
FRED MEYER STORES	INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES
By: ______________________	By: S Bradley Van Cleve

ORDER NO. 01-777

Portland General Electric Company
P.U.C. Oregon No. E-17 Original Sheet No. 125-1

SCHEDULE 125
RESOURCE VALUATION MECHANISM

PURPOSE

To recognize the difference between the market price and costs of power on an annual basis.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service calculated under all rate schedules specified herein, including contracts, except where explicitly exempted.

PART A – LONG-TERM RESOURCES

Part A shall reflect the difference between the projected total cost of power (including a credit for any Company provided Ancillary Services) from long-term resources owned or controlled by the Company including associated transmission by others and the market price of an equivalent amount of power. The market price shall be based on the forward price curve that the Company uses to set the Annual Fixed Price Option. Long-term resources are all generating plants and power purchases with an initial term longer than five years, except BPA Subscription Power.

PART B – SHORT-TERM RESOURCES

Part B shall reflect the difference between the projected cost of power from short-term resources including associated transmission by others and the market price of an equivalent amount of power. The market price shall be based on the forward price curve that the Company uses to set the Annual Fixed Price Option. Short-term resources are all resources that do not meet the definition of long-term resources except BPA Subscription Power.

EXHIBIT A
PAGE 1 OF 5

SCHEDULE 125 (Continued)

PART B – SHORT-TERM RESOURCES (Continued)

A Large Nonresidential Consumer may provide Preliminary Direct Access Notice 12 months in advance of the next Part B adjustment informing the Company that it does not want the Company to plan to serve its load. In such case, the Consumer will be exempt from the Part B adjustment beginning with the next Part B adjustment and continuing until it gives 12-month notice to return to Part B eligible status. The first such notice shall be for the 12-month period beginning January 1, 2003.

PART C – ADVERSE HYDRO CONDITIONS

Part C shall reflect the projected difference in Net Variable Power Costs (as defined in Schedule 127) between expected and normal hydro conditions, on or about August 1, 2001, for the period of October 2001 through December 2002 of $xxxx.

ADJUSTMENT RATE

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

		Adjustment Rate	
Schedule	Part A	Part B	Part C
7	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
15	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
32	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
38	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
48	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
49	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
82 Small Nonresidential	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
Large Nonresidential			
Secondary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
Primary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
Subtransmission	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh

ORDER NO. 01-777

SCHEDULE 125 (Continued)

Adjustment Rate (continued)

			Adjustment Rate	
Schedule		Part A	Part B	Part C
83	Secondary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Primary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Subtransmission	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
91		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
92		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
93		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
97		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
99	(where applicable)	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
515		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
532		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
549		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
583	Secondary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Primary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Subtransmission	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
591		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
592		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh

ANNUAL ADJUSTMENT REVISIONS

The adjustment rates for Part A and Part B shall be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. For the first year of implementation, the service year will last 15 months, beginning on October 1, 2001 and ending on December 31, 2002, causing the filing to be made on or by August 15, 2001. Part C will be set to zero effective January 1, 2003.

EXHIBIT A
PAGE 3 OF 5

SCHEDULE 125 (Continued)

Part A shall be based on the Company's most recent rate order, adjusted for the service year. Part B shall be based on the Company's purchase obligations for the next calendar year entered into on or before September 15 of the filing year (August 1, 2001 for the October 2001 through December 2002 period). The Part A and Part B revisions shall reflect updates to the following:

- Applicable resources
- Company market power purchases
- Costs of fuel and transportation
- Hydro operating constraints imposed by governmental agencies
- Market power prices (including transmission to the Company)
- Transmission and ancillary services
- Retail load forecast

LARGE NONRESIDENTIAL LOAD SHIFT TRUE-UP

If the net difference of load between:

1. Consumers who provided Preliminary Direct Access Notice and subsequently selected the Annual Fixed Price Option of Schedule 83 (Category 1 Consumers) and

2. Consumers who did not provide Preliminary Direct Access Notice and did not select the Annual Fixed Price Option of Schedule 83 (Category 2 Consumers)

is greater than 25 aMW, the Company may adjust the Part A or Part B adjustment for large nonresidential consumers to account for such difference in load.

If the load of Category 1 Consumers exceeds that of Category 2 Consumers, the Company will adjust the Part A adjustment for large nonresidential consumers to reflect the deviation between the market prices used to set the Part A adjustment and actual market prices experienced in acquiring power to meet the difference in load.

If the load of Category 2 Consumers exceeds that of Category 1 Consumers, the Company will adjust the Part B adjustment for large nonresidential consumers to reflect the deviation between the market prices used to set the Part B adjustment and actual market prices experienced in disposing of power to meet the difference in load.

SCHEDULE 125 (Concluded)

RESOURCE CHANGES

The Part A Adjustment Rates shall be modified at any time to reflect changes in the Company's resources resulting from the implementation of all or a portion of a Commission-approved Resource Plan, any other Commission-approved resource change, or the catastrophic failure of a resource. In the case of a catastrophic failure, Part A shall be adjusted by replacing the variable costs of the resource with the cost of replacement power.

EXHIBIT A
PAGE 5 OF

Portland General Electric Company
P. U. C. Oregon No. E-17 Original Sheet No. 127-1

SCHEDULE 127
POWER COST ADJUSTMENT

PURPOSE

To recognize in rates differences in actual net power costs from those assumed in base energy rates.

APPLICABLE

To all bills for electric service calculated under Schedules 7, 15, 32, 38, 48, 49, 83 (Annual Fixed Price Option only), 91, 92, 93, 97, and contracts, except for BPA power delivered for service to residential consumers and also where explicitly exempted.

NET VARIABLE POWER COSTS

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

- Exclude the Regional Power Act Exchange Credit, the cost of BPA Subscription Power, and payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude the results of any transaction arising from the Company's merchant trading business; that is, transactions relating to the acquisition and disposition of wholesale power, hedges, options and other financial instruments solely for the Company's own account and at its own risk.
- Include as a cost (or exclude from revenue) all losses (except those related to merchant trading) that the Company incurs, or is reasonably expected to incur, as a result of any non-retail customer failing to pay the Company for the sale of power during the period in which this schedule is in effect.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.

BASE NVPC

The Base NVPC are defined as the NVPC used to develop existing rate schedules including Parts A and B of Schedule 125. The current Base NVPC are:

$x,xxx	October 2001 through December 2002

ENERGY REVENUES

Energy Revenues are defined as the total revenues from Energy Charges of tariff Schedules 7 through 99, plus all charges or credits under Schedule 125, Resource Valuation Mechanism and Schedule 131, Special Contract Adjustment. To the extent that the Energy Charges of a particular rate schedule contain elements not directly related to the cost of power (e.g. system usage charges), such elements shall be excluded from Energy Revenues.

BASE ENERGY REVENUES

The Base Energy Revenues are defined as the Energy Revenues, excluding Part C of Schedule 125 and Schedule 131, forecast from existing tariffs and the load forecast used to develop the Base NVPC. The current Base Energy Revenues are:$x,xxx October 2001 through December 2002

POWER COST VARIANCE

The Power Cost Variance (PCV) is the difference between actual and Base NVPC less the difference between actual and Base Energy Revenues for the period October 2001 through December 2002. The Adjustment Amount shall be determined according to the following based on the level of the PCV:

Power Cost Variance	Adjustment Amount
-$28.0 million to $28.0 million	zero
$28.0 million to $38.0 million	50% of PCV between $28.0 million and $38.0 million
$38.0 million to $100 million	$5.0 million plus 85% of PCV between $38.0 million and $100 million
$100 million to $200 million	$57.7 million plus 90% of PCV between $100 million and $200 million
over $200 million	$147.7 million plus 95% of PCV in excess of $200 million
-$28.0 million to -$38.0 million	50% of PCV between -$28.0 million and -$38.0 million
-$38.0 million to -$100 million	-$5.0 million plus 85% of PCV between -$38.0 million and -$100 million
-$100 million to -$200 million	-$57.7 million plus 90% of PCV between -$100 million and -$200 million
less than -$200 million	-$147.7 million plus 95% of PCV less than -$200 million

EXHIBIT B

POWER COST ADJUSTMENT ACCOUNT

The Company will maintain a Power Cost Adjustment Account to record overcollections and undercollections. The Account will contain the difference between the actual Adjustment Amount and revenues collected/credited under this schedule. Interest will accrue on the account at the Company's authorized rate of return beginning January 1, 2003. In addition, there shall be an amount added to the balance on January 1, 2003 equal to the product obtained by multiplying ½ the balance on December 31, 2002 by an interest rate equal to 15 months of the Company's authorized rate of return.

POWER COST ADJUSTMENT RATE

The Power Cost Adjustment Rate shall be revised on a quarterly basis. It shall be determined as an amount per kilowatt-hour, carried to the nearest 0.001 cents per kilowatt-hour, necessary to bring the projected balance of the Power Cost Adjustment Account (including the projected Adjustment Amount for the period October 2001 through December 2002) to zero at the end of 2002. Each quarter the Company will forecast the PCV and resulting Adjustment Amount for the October 2001 through December 2002 period based on actual results to date and a forecast of the remaining months. This amount less collections to date under this schedule will be the projected balance of the Power Cost Adjustment Account. The new Power Cost Adjustment Rate will be equal to this projected balance divided by the load forecast minus the amount of power delivered by BPA to PGE residential consumers for the remaining period.

If this tariff is terminated for any reason prior to December 31, 2002, the Commission shall determine the Adjustment Amount on a prorated basis consistent with principles of this schedule. In such case, or when this tariff otherwise terminates, any balance in the Power Cost Adjustment Account shall be amortized to rates over a period to be determined by the Commission.

Each Consumer's billing shall state the dollar amount of this adjustment.

TIME AND MANNER OF FILING

Forty-five days prior to the effective date of the revised Power Cost Adjustment Rate, the Company shall submit to the Commission the following information:

(1) A letter of transmittal that summarizes the proposed changes under the schedule.
(2) A revised rate schedule page that reflects the new quarterly Power Cost Adjustment Rate.
(3) Working papers supporting the calculation of the revised Power Cost Adjustment Rate.

ADJUSTMENT RATE

The Power Cost Adjustment Rate, applicable for service on and after the effective date of this rate schedule shall be:

Schedule		Adjustment Rate
7		0.000 ¢ per kWh
15		0.000 ¢ per kWh
32		0.000 ¢ per kWh
38		0.000 ¢ per kWh
48		0.000 ¢ per kWh
49		0.000 ¢ per kWh
83*	Secondary	0.000 ¢ per kWh
	Primary	0.000 ¢ per kWh
	Subtransmission	0.000 ¢ per kWh
91		0.000 ¢ per kWh
92		0.000 ¢ per kWh
93		0.000 ¢ per kWh
97		0.000 ¢ per kWh
99	(where applicable)	0.000 ¢ per kWh

* **Annual Fixed Price Option only**

ORDER NO. 01-777

SCHEDULE 131
SPECIAL CONTRACT ADJUSTMENT

PURPOSE

To refund to Consumers $___ million of special contract collections.

APPLICABLE

To all bills for electric service.

ADJUSTMENT RATE

- ____ cents per kwh

TERM

This adjustment shall terminate on December 31, 2002.

EXHIBIT C
PAGE 1 OF 1

ORDER NO. 01-777

Portland General Electric Company
P.U.C. Oregon No. E-17 Original Sheet No. XX-1

SCHEDULE 130
SHOPPING INCENTIVE RIDER

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Consumers using less than 1 MWa at a site in the prior calendar year (after adjusting to remove the effects of any demand exchanges).

SHOPPING INCENTIVE (PART A)

Consumers for whom this rider is applicable and who elect to receive service under Schedule 583 will receive a Shopping Incentive credit of 0.500¢ per kWh. The Shopping Incentive will be limited to the first ten percent (10%) of Qualifying Consumer Load, measured on a kWa basis that is served under Schedule 583, where Qualifying Consumer Load is equal to the estimated total load of Large Nonresidential Consumers using less than 1 MWa at a site in the prior calendar year (after adjusting to remove the effects of any demand exchanges). No Consumer, business, or group of affiliated businesses with common or similar ownership shall receive Shopping Incentives for single or multiple locations that represent more than 2.5% of Qualifying Consumer Load.

SHOPPING INCENTIVE RECOVERY ADJUSTMENT (PART B)

The Shopping Incentive Recovery Adjustment shall be applied to all applicable Large Nonresidential Consumers.

At least 30 days prior to January 1 of each year (October 1, 2001 for the period October 2001 through December 2002) the Company will file an adjustment rate to recover credits provided under this Schedule. The rate shall be set to recover the estimated credits to be given during the year plus any over- or under-collections during prior periods.

Effective October 1, 2001 the Shopping Incentive Recovery Adjustment shall be

_______ cents per kWh

EXHIBIT D
PAGE 1 OF

Advice No. 00-14
Issued ____________

APPENDIX D
PAGE 23 OF 28

Effective for service
on and after October 1, 2001

SCHEDULE 130
SHOPPING INCENTIVE RIDER (Concluded)

TERM

Shopping Incentive credits under this rider will expire three years after direct access is first available under the provisions of section 2, chapter 865, Oregon Laws 1999.

The Shopping Incentive Recovery Adjustment shall expire four years after direct access is first available under the provisions of section 2, chapter 865, Oregon Laws 1999.

RULES AND REGULATIONS

Service under this schedule is subject to the General Rules and Regulations contained in the Tariff of which this schedule is a part.

EXHIBIT I
PAGE 2 OF

Exhibit E

Allocation of Hydro Adjustment to Months

		Mwh Adjustment
Oct	2001	-65,780
Nov	2001	-42,465
Dec	2001	-44,999
Jan	2002	-97,437
Feb	2002	-102,967
Mar	2002	-83,851
Apr	2002	24,525
May	2002	33,976
Jun	2002	-11,485
Jul	2002	9,707
Aug	2002	-46,502
Sept	2002	24,819
Oct	2002	8,090
Nov	2002	32,132
Dec	2002	62,236
Total		-300,000

Tonkon Torp LLP
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AUG 2001
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August 20, 2001

Janice Fulker, Administrator
Regulatory and Technical Division
Oregon Public Utility Commission
550 Capitol St. NE, Suite 215
Salem, OR 97301-2551

Re: UE 115 Monet Run

Dear Ms. Fulker:

Pursuant to Judge Grant's Post-Hearing Conference Memorandum dated July 17, 2001, enclosed is PGE's "final draft" Monet Run. This was delayed due to settlement discussions among the Parties. Staff, ICNU, CUB and PGE held settlement discussions on August 13, 15, 16 and 17, 2001, concerning the June 1 and July 27, 2001, Monet Runs and the corrections and updates to the June 1 Monet Run that would be included in the "final draft" Monet Run and the final Monet Run used to establish final pricing in this docket in September 2001.

Attached to this letter is a list of 16 corrections and updates that were included in PGE's July 27, 2001, Monet Run that were not included in the June 1, 2001, Monet Run distributed to the parties. This list was attachment 3 to PGE's comments filed August 9, 2001, on the July 27, 2001, Monet Run. Staff and PGE have agreed that the "final draft" Monet Run and the September 2001 Monet Run will be based on the inputs to the June 1 Monet Run with the adjustments contained in items 2, 10-14 and 16 on the attached list of corrections and updates, and will not include the other items on the attached list. In addition, PGE will remove from these runs a merchant trading transaction that was inadvertently included in the June 1, 2001, Monet Run. CUB and ICNU will not oppose the use of the June 1, 2001, Monet Run with the inclusion of these corrections and updates. Staff and PGE have agreed that the September Monet Run will be based on the "final draft" Monet Run updating only the most recent gas and electric forward curves. CUB and ICNU will not oppose this agreement.

At the request of ICNU, the date for final pricing in this docket will be September 12, not September 11.

PGE withdraws its motion to reopen the record filed August 9, 2001.

Very truly yours,

Michael M. Morgan

MMM/pcs
Enclosure
cc: UE 115 Service List
Mr. Maury Galbraith

001991\00131\413458 V001

Attachment 3 to
PGE's August 9 Comments

On Thursday, August 2nd, PGE met with Staff and discussed the following corrections and updates to the June 1st Monet model run that were incorporated into the July 27th Monet model run:

1. Updating the cost of coal for Boardman, including transportation, based on the most recent information available. This update was incorporated in the June 1, 2001 Monet run.
2. Updating Coyote fuel costs for the cost of gas to operate the auxiliary boiler to produce steam, consistent with the 2nd Stipulation with Staff on revenue requirement issues and Commission Order 01-489.
3. Updating the Wells Settlement contract output based on hydro output.
4. Update contract cost for the Portland Hydro Project based on most recent available information.
5. Utilize 48-month average for Thermal Availability and Thermal Maintenance based on historical data through 12/31/00 (the most recent data available).
6. Update firm Gas Transportation for most recent tariff information available.
7. Update variable Gas Transportation costs to include losses due to compressor usage.
8. Update cost of Ogden/Mt. Tabor contract based on most recent available information.
9. Update cost of Lake Oswego Street Lighting contract based on most recent available information.
10. Incorporate BPA subscription power at expected contract cost (28.3 mills) rather than forecast market.
11. Correct the load forecast for two months to match forecast provided in PGE's Rebuttal Testimony (STF01AE).
12. Utilize most recent forward curves for market gas/electricity.
13. Utilize most recent contracts for gas/electricity.
14. Incorporate Staff/PGE Stipulation on expected Hydro output.
15. Expected output of Vancycle Ridge contract updated to 10 aMW using most recent available information.
16. Correct capacity of Chelan Exchange In contract from 50 MW to 25 MW in October 2002.

RECEIVED
AUG 7 2001
Public Utility Commission of Oregon
Administrative Hearings Division

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	))))	SUPPLEMENTAL REVENUE STIPULATION REGARDING FRANCHISE FEES AND STEAM SALES

This stipulation (Supplemental Revenue Stipulation) is entered into for the purpose of resolving Portland General Electric Company's (PGE) requested revenue requirements related to franchise fees and steam sales in this docket. Specifically, this Supplemental Revenue Stipulation represents a supplement to the stipulation entered into by PGE, the Staff of the Oregon Public Utility Commission (Staff), and Fred Meyer Stores on March 7, 2001.

I. INTRODUCTION

On October 2, 2000, PGE filed Advice No. 00-14 to produce a $324 million increase in its base prices to its customers. The filing was based on a projected test year of 2002.

Not addressed in the March 7, 2001 Stipulation were revenue requirements adjustments regarding the treatment of franchise fees to cities in PGE's service territory and steam sales at PGE's Coyote Springs generating plant. The parties signing this Supplemental Revenue Stipulation (Parties) agree to modify PGE's currently stipulated revenue requirement as stated below. The Parties submit this Supplemental Revenue Stipulation to the Commission and request that the Commission approve the settlement as presented.

II. TERMS OF STIPULATION

1. The Parties to this Supplemental Revenue Stipulation agree that PGE will adjust its revenue requirement request to reflect the adjustments listed in Attachment A to this Supplemental Revenue Stipulation. The parties agree to calculate the revenue requirement impact of the adjustments listed in Attachment A consistent with the final Commission approved Cost of Capital in this case.

2. The Parties recommend that the Commission approve the various rate base, expense, and other revenue adjustments described in Attachment A.

3. The Parties agree to adjust "Revenue Sensitive Costs" to incorporate a 2.26% Franchise Fee, and include a calculation for Franchise Fee Costs at 2.26% in "Franchise and Other Tax" in all revenue requirement calculations (see Attachment B). The Parties agree that

APPENDIX E

PGE will use the adjusted "Revenue Sensitive Costs" for calculating rate adjustments subsequent to this docket until the Commission issues an order changing the Franchise Fee rate.

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

5. This Supplemental Revenue Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Supplemental Revenue Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Supplemental Revenue Stipulation at the hearing, if any, and recommend that the Commission issue an order adopting the settlements contained herein.

6. If this Supplemental Revenue Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that departs from the terms of this Supplemental Revenue Stipulation, the Parties to this Supplemental Revenue Stipulation 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 Supplemental Revenue Stipulation. Notwithstanding this reservation of rights, the Parties to this Supplemental Revenue Stipulation agree that they will continue to support the Commission's adoption of the terms of this Supplemental Revenue Stipulation.

7. The Parties have negotiated this Supplemental Revenue Stipulation as an integrated document. If the Commission rejects all or any material portion of this Supplemental Revenue Stipulation or imposes additional material conditions in approving this Supplemental Revenue Stipulation, any Party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's order.

8. By entering into this Supplemental Revenue Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principals, methods or theories employed by any other party in arriving at the terms of this Supplemental Revenue Stipulation. No Party shall be deemed to have agreed that any provision of this Supplemental Revenue Stipulation is appropriate for resolving issues in any other proceeding.

9. This Supplemental Revenue Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Supplemental Revenue Stipulation is entered into by each Party on the date entered below.

Dated this _____ day of __________________, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

______________________ 8/6/01

By: J. Jeffrey Dudley

PACIFICORP

____

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

____

By: ______________________

CITIZENS' UTILITY BOARD

____

By: ______________________

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

____

By: ______________________

FRED MEYER STORES

____

By: ______________________

[OTHER]

____

By: ______________________

This Supplemental Revenue Stipulation is entered into by each Party on the date entered below.

Dated this 26th day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

By: ______________________

PACIFICORP

By: ______________________

FRED MEYER STORES

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

David B. Hatton

By: David B. Hatton
Of Attorneys for Staff

[OTHER]

By: ______________________

CITIZENS' UTILITY BOARD

By: ______________________

ORDER NO. 01-777

This Supplemental Revenue Stipulation is entered into by each Party on the date entered below.

Dated this _____ day of ________________, 2001.

PORTLAND GENERAL ELECTRIC COMPANY	INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES
____________________ By: ________________	____________________ By: ________________
PACIFICORP	FRED MEYER STORES
____________________ By: ________________	____________________ By: Michael L. Kurtz
STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON	[OTHER]
____________________ By: ________________	____________________ By: ________________
CITIZENS' UTILITY BOARD	
____________________ By: ________________	

Attachment "A"

The Stipulated Adjustments are described below and summarized in Attachment A1. The revenue requirement impact of each of the adjustments (including revenue sensitive costs) will be determined once the Cost of Capital issue (S-0) is determined.

S-55 Franchise Fees: Increase Franchise and Other Tax by $794,000 to reflect a revenue-based calculation on 2002 sales to customers. Adjust "Revenue Sensitive Costs" to incorporate a 2.26% Franchise Fee, and include a calculation for Franchise Fee Costs at 2.26% in "Franchise and Other Tax" in all revenue requirement calculations.

S-56 Steam Sales: For the UE-115 test year, PGE will include all costs and revenues expected for steam sales. Decrease Other Revenue by $306,000 to remove imputed steam sales as originally filed in UE-115. Increase Other Revenue by $1,143,000 to reflect estimated steam sales revenue for 2002. Increase the heat rate in the "Monet" power cost model to reflect expected steam sales for each applicable month. If steam sales are expected to be supplied from the auxiliary boiler, increase energy output from Coyote Springs 1 and include cost of increased gas usage from the auxiliary boiler.

Attachment A1

Other Revenue, Operating Costs, Rate Base

Financial Summary Reflecting Stipulated Positions **Attachment A1**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	FERC Wholesale Fee (S-1)	Montana Production Tax (S-2)	Colstrip O & M (S-3)	Transmission O & M (S-4)	FERC Hydro Fee (S-5)	Income Tax Apportion (S-6)	Severance Program (S-7)	OAL Sale (S-8)	PGH Billings (S-9)	Retail Unbundling Allocation (S-10)
Retail Revenues										
Other Revenue										
Production O&M			1,043		(14)			(83)		
Transmission O&M			25					(28)		
Distribution O&M								(223)		
Purchased Power										
Generation										
Wheeling										
A&G	(372)				714			108	(436)	303
Customer Service										435
Depr. & Amort.							66	100		
Other Taxes		450								
Rate Base (excluding working cash)								(439)		

Revenue Requirement Category	Beaver Turbine (S-11)	Other Revenue (S-12)	State Tax Credit (S-13)	Remove SERP Rate Base & MDCP Expense (S-14)	Remove Trojan (S-15)	Remove Neil (S-16)	Remove Other Debits & Credits (S-17)	Solar For Schools (S-18)	Salmon Springs Reclassification (S-19)	Green Power Purchase (S-20)
Retail Revenues										
Other Revenue							(589)		183	
Production O&M						2,400				
Transmission O&M										
Distribution O&M										
Purchased Power										(420)
Generation										
Wheeling										
A&G				(4,645)		1,418				
Customer Service								(55)		
Depr. & Amort.	182				(16,584)		(959)			
Other Taxes	14									
Rate Base (excluding working cash)	2,789			(2,122)	(102,904)		181			

ORDER NO. 01-777

APPENDIX E
PAGE 8 OF 12

Financial Summary Reflecting Stipulated Positions **Attachment A1**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	Property Tax Unbundling Correction (S-21)	Y2K Deferral (S-22)	Two Cities (S-23)	Miscellaneous Electric Revenues (S-24)	CRM (S-25)	Reduce Customer Acct. Non-Labor Exp. (S-26)	Category "A" Advertising Reduction (S-27)	Public Purpose Adjustment (S-28)	Remove Marketing & Sales Expense (S-29)	T&D O&M (S-30)
Retail Revenues										
Other Revenue				998						
Production O&M										
Transmission O&M										(1,505)
Distribution O&M										(990)
Purchased Power										
Generation										
Wheeling			129							
A&G								(149)		
Customer Service						(1,600)	(2,405)	(550)	(800)	
Depr. & Amort.										
Other Taxes										
Rate Base (excluding working cash)			96							

Revenue Requirement Category	Reduce A & G Accounts N44173 & N44174 (S-31)	Remove Suppl. Executive Retirement Plan (S-32)	Bonus & Incentive Adjustment (S-33)	Workforce Level Adjustment (S-34)	OPUC Wage Formula Adjustment (S-35)	Distribution Plant Reduction (S-36)	Materials & Supplies Adjustment (S-37)	Y2K Amortization (S-38)	NEIL Amortization (S-39)	Accumulated Deferred Taxes (S-40)
Retail Revenues						1,075				
Other Revenue										
Production O&M										
Transmission O&M										
Distribution O&M										
Purchased Power										
Generation										
Wheeling										
A&G	(1,000)	(1,250)	(2,237)	(2,411)	(1,550)					
Customer Service				(2,411)						
Depr. & Amort.						(60)		(1,977)		
Other Taxes			(240)	(518)	(167)	(30)				
Rate Base (excluding working cash)			(602)	(1,046)	(336)	(2,000)	(3,681)	(4,942)		(22,832)

ORDER NO. 01-777

APPENDIX E
PAGE 9 OF 12

Financial Summary Reflecting Stipulated Positions — **Attachment A1**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	Income Tax Adjustments (S-41)	Remove Property Sales Gains (S-42)	Depreciation Study Adj. (S-43)	SB 1149 Implementation Costs (S-44)	CIS/IT Disallowance Adjustments (S-45)	Franchise Fee (S-55)	Steam Sales Adjustment (S-56)			
Retail Revenues										
Other Revenue							837			
Production O&M										
Transmission O&M										
Distribution O&M										
Purchased Power										
Generation										
Wheeling										
A&G				416						
Customer Service				376						
Depr. & Amort.		477	(3,567)							
Other Taxes						794				
Rate Base (excluding working cash)			1,784	459						

S:\RATECASE\OPUC\DOCKETS\UE-115\Settlement\Stip Test FF and Steam Sales\[Stip Test Exhibits.xls]Adjustments

Attachment B

Revenue Sensitive Costs

Revenue Sensitive Costs:	
Revenues	1.00000
Franchise Fees	0.02260
OPUC Fee	-
O&M Uncollectibles	0.00500
State Taxable Income	0.97240
State Tax @ 6.65%	0.06471
Federal Taxable Inc.	0.90769
Federal Tax @ 35%	0.31769
Total Income Taxes	0.38240
Total Rev. Sensitive Costs	0.41000
Utility Operating Income	0.59000
Net To Gross Factor	1.69492

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Public Utility Commission of Oregon
Administrative Hearings Division

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149	STIPULATION CONCERNING RESIDENTIAL RATE DESIGN FOR SCHEDULE 7

This Stipulation is between Portland General Electric Company (PGE) and the Staff of the Public Utility Commission of Oregon (Staff). The parties have filed testimony on how the benefits and burdens of Subscription Power from the Bonneville Power Administration (BPA) should be flowed through to eligible customers, how the cash benefits BPA will pay to PGE under the Residential Exchange Settlement Agreement between them will be passed through to eligible customers, and how the Resource Valuation Mechanism in PGE's Schedule 125 should be applied to the residential and small farm classes of customers.

The parties held settlement conferences on June 26, 2001, July 10, 2001, July 18, 2001, July 23, 2001, and August 2, 2001. As a result of these settlement conferences, the parties have negotiated this Stipulation to resolve the matters described above. The parties agree to and request that the Commission adopt orders in this Docket as follows:

1. PGE shall value Subscription Power, for the 15 months beginning October 1, 2001 and ending December 31, 2002, and for each succeeding calendar year beginning with 2003, by comparing the cost of Subscription Power to the market value of that power. PGE will determine market value using the same market price on the same day that it establishes the market price for the residential energy charge. The difference between the value of the Subscription Power and the price of that power to PGE will be credited or charged to customers under Schedule 102. For

Residential customers, the credit or charge will apply only to the first 225 kWh of energy used each month. The credit or charge shall equal the difference in the market value of the Subscription Power and the price of the Subscription Power charged by BPA to PGE.

2. The cash BPA pays to PGE under the Residential Exchange Settlement Agreement will be credited to residential customers eligible to receive the cash on a per-kWh basis applied only to all kWh used by such customers in excess of 225 kWh per month.

3. PGE will apply the credit or charge produced by the Resource Valuation Mechanism in Schedule 125, including parts A, B and C of Schedule 125, on a per-kWh basis to all kWh of energy use of all of PGE's customers within each customer class.

4. If the credits and charges described above, and the market price for energy, produce proposed rates for residential customers under which the price differential between the first block of 225 kWh of energy use and the second block of energy use in excess of 225 kWh is less than 10 mills, then the charges and credits applied to each block shall be adjusted so that the price differential between the two blocks is 10 mills. If the proposed rates produce a price differential between the two blocks of more than 25 mills, then the charges and credits applied to each block shall be adjusted to produce a price differential between the two blocks of 25 mills. In each case, however, the benefits and burdens of Subscription Power shall be passed through fully and only to residential and small farm customers eligible to receive such Power.

5. If, subsequent to October 1, 2001, BPA modifies the amount of Subscription Power available to PGE, the size of the first rate block will be adjusted to reflect the approximate amount of Subscription Power available to each residential customer. If, subsequent to October 1, 2001, the rate for BPA Subscription Power is changed, PGE will file to adjust the rate for the first rate block to reflect the change in the BPA rate notwithstanding the provisions of paragraph 4 of this Stipulation.

6. If the average amount of Subscription Power available to each residential customer differs substantially from 225 kWh per customer per month, PGE will adjust the size of the first block of energy to approximate the amount of Subscription Power available to each residential customer.

7. PGE will maintain a balancing account to ensure that all of the benefits and burdens of Subscription Power and cash payments from BPA under the Residential Exchange Settlement Agreement are provided to or collected from eligible customers.

8. Schedule 7 shall include a customer or basic charge of $10 per customer per month.

9. This Stipulation represents a settlement in compromise of the positions of the parties with respect to the matters covered by this Stipulation. This Stipulation may not be cited or used as precedent in any proceeding except for those proceedings implementing the terms of this Stipulation.

10. The Parties agree to support this Stipulation before the Commission and before any court in which this Stipulation may be considered. 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 rejecting this Stipulation or adding such material condition.

11. The Parties shall file this Stipulation with the Commission.

12. 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 only one agreement.

13. The parties to any dispute concerning this Stipulation agree to confer and make a good faith effort to resolve such dispute prior to bringing an action or complaint to the Commission or any court with respect to such dispute.

DATED this 10th day of August, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

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ORDER NO. 01-777

PORTLAND GENERAL ELECTRIC
Issues Summary
UE 115 - Test Year Ending December 2002
($000)

Item	Issue	Revenue Requirement Effect 2002	
	Revenue Requirement on the Company's Filed Results	$323,982	
	Adjustments (Base Rates)		
S-0	Rate of Return (Long Term Debt and Preferred, see S-41 for interest effect)	($4,258)	
S-00	Rate of Return (ROE @ 10.50%)	(16,476)	
S-1	FERC Wholesale Fee	(374)	
S-2	Montana Producers Tax	454	
S-3	Colstrip O & M	1,078	
S-4	Transmission O & M	0	
S-5	FERC Hydro Fee	705	
S-6	Income Tax Apportion	0	
S-7	Trojan Severance Program	67	
S-8	Oregon Analytical Lab Sale	(184)	
S-9	PGH Billings	(439)	
S-10	Retail Unbundling Corrections	745	
S-11	Beaver Turbine	553	
S-12	Other Revenues	0	
S-13	State Tax Credit	0	
S-14	Remove SERP Rate Base and MDCP O & M	(4,956)	
S-15	Remove Trojan Assets	(33,742)	
S-16	Remove NEIL	3,850	
S-17	Remove Other Offsetting Liabilities	(354)	
S-18	Solar for Schools	(55)	
S-19	Salmon Springs Reclassification	(183)	
S-20	Green Power Purchase	(424)	
S-21	Property Tax Unbundling Correction	0	
S-22	Y2K Deferral	0	
S-23	Two Cities Wheeling Expense	142	
S-24	Miscellaneous Electric Revenues	(1,001)	
S-26	Remove Customer Accounts Non-Labor Expenses	(1,613)	
S-27	Category "A" Advertising Reduction	(2,378)	
S-28	Public Purpose Adjustment	(705)	
S-29	Remove Marketing and Sales Expense	(807)	
S-30	Transmission and Distribution Expense Reduction	(1,834)	
S-31	Reduce A & G Information Technology Costs	(1,008)	
S-32	Remove Supplemental Executive Retirement Plan	(1,261)	
S-33	Bonus and Incentive Adjustment	(2,576)	
S-34	Workforce Level Adjustment	(5,520)	
S-35	OPUC Wage Formula Adjustment	(1,775)	
S-36	Distribution Plant Reduction	(1,395)	
S-37	Materials & Supplies Adjustment	(469)	
S-38	Y2K Amortization	(2,624)	
S-39	NEIL Amortization	0	
S-40	Accumulated Deferred Taxes	(2,916)	
S-41	Miscellaneous Income Tax Adjustments	797	
S-42	Remove Property Sales Gains	481	
S-43	Depreciation Study Adjustment	(3,371)	
S-44	SB 1149 Implementation Costs	857	
S-45	CIS/IT Disallowance Adjustments	0	
S-55	Franchise Fee (Base)	800	
S-56	Coyote Steam Sales Adjustment	(839)	
	Franchise Fee on Revenue Change	8,904	
	Demand Exchange	(100)	
	Weather Wise	(161)	
	Load Forecast Revenue Update	33,068	
	Additional Non-Power O & M Reduction	(6,985)	
	Variable Power Cost--Monet Update 8/29/01(Including S-25, Weather Option)	118,272	
	Rounding	17	
	Total Adjustments (Base Rates)	70,007	
	Total Revenue Requirements Change (Base Rates)	393,989	36.0%

APPENDIX G

PORTLAND GENERAL ELECTRIC - UE 115
Results of Operations
Twelve Months Ended December 31, 2002
($000)

30-Aug-01
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		2002 Results Per Company Filing (1)	Adjustments (2)	2002 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	**Operating Revenues**					
2	Sales to Consumers	$1,128,504	($32,842)	1,095,662	$393,989	$1,489,651
3	Sales for Resale	0	0	0	0	0
4	Other Operating Revenues	15,236	749	15,985	0	15,985
5	Total Operating Revenues	$1,143,740	($32,093)	$1,111,647	$393,989	$1,505,636
6	**Operation & Maintenance**					
7	Net Variable Power Cost	$627,942	$116,987	$744,929	$0	$744,929
8	Production O&M	63,410	946	64,356	0	64,356
9	Trojan O&M	3,702	2,400	6,102	0	6,102
10	Transmission O&M	7,781	(1,508)	6,273	0	6,273
11	Distribution O&M	58,181	(1,213)	56,968	0	56,968
12	Customer & MBC O&M	47,555	(10,623)	36,932	0	36,932
13	Uncollectible Expense	5,642	(164)	5,478	1,970	7,448
14	Administrative and General	108,517	(14,617)	93,900	0	93,900
15	Total Operation & Maintenance	$922,730	$92,208	$1,014,938	$1,970	$1,016,908
16	Depreciation	155,232	(3,465)	151,767	0	151,767
17	Amortization	45,682	(18,857)	26,825	0	26,825
18	Property & Payroll Tax	41,127	(941)	40,186	0	40,186
19	Franchise & Other Tax	25,191	502	25,693	8,904	34,597
20	Utility Income Tax	(35,763)	(39,948)	(75,711)	150,662	74,951
21	Total Operating Expenses & Taxes	$1,154,199	$29,498	$1,183,697	$161,536	$1,345,233
22	**Net Operating Revenues**	($10,459)	($61,591)	($72,050)	$232,453	$160,403
22	**Average Rate Base**					
23	Electric Plant in Service	$3,636,902	($784)	$3,636,118	$0	$3,636,118
24	Accumulated Depreciation & Amortization	(1,757,582)	1,446	(1,756,136)	0	(1,756,136)
25	Accumulated Deferred Income Taxes	(165,850)	7,557	(158,293)	0	(158,293)
26	Accumulated Deferred Inv. Tax Credit	(25,599)	4,288	(21,311)	0	(21,311)
27	Net Utility Plant	$1,687,871	$12,507	$1,700,378	$0	$1,700,378
28	Net Trojan Investment	137,738	(137,738)	0	0	0
29	Weatherization Investment	0	0	0	0	0
30	Working Cash	51,477	1,315	52,792	7,205	59,997
31	Fuel	11,368	0	11,368	0	11,368
32	Materials & Supplies	26,292	(3,681)	22,611	0	22,611
33	Other Deferred Debits	17,429	(7,611)	9,818	0	9,818
34	Deferred Gains on Sales	(21,996)	0	(21,996)	0	(21,996)
35	Other Deferred Credits	(22,078)	5,870	(16,208)	0	(16,208)
36	Y2K Deferral	4,942	(4,942)	0	0	0
37	Total Average Rate Base	$1,893,043	($134,281)	$1,758,763	$7,205	$1,765,968
38	Rate of Return	-0.55%		-4.10%		9.08%
	[illegible]	-7.98%		-14.77%		10.50%

ORDER NO. 01-777

30-Aug-01
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PORTLAND GENERAL ELECTRIC
Results of Operations
Twelve Months Ended December 31, 2002
($000)

	Income Tax Calculations	2002 Per Company Filing (1)	Adjustments (2)	2002 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$1,143,740	($32,093)	$1,111,647	$393,989	$1,505,636
2	Book Expenses Other than Depreciation	1,034,729	72,911	1,107,640	10,874	1,118,514
3	State Tax Depreciation	155,232	(3,465)	151,767		151,767
4	Interest	68,353	(7,184)	61,169	251	61,420
5	Schedule M Differences	(67,382)	6,846	(60,536)		(60,536)
6	State Taxable Income	($47,192)	($101,201)	($148,393)	$382,864	$234,471
7	State Income Tax @ 6.6547%	($3,214)	($6,663)	($9,877)	$25,478	$15,601
8	Net State Income Tax	($3,214)	($7,580)	($9,877)	$25,478	$15,601
9	Additional Tax Depreciation	0	0	0	0	0
10	Other Schedule M Differences	0	0	0	0	0
11	Federal Taxable Income	($43,978)	($93,621)	($137,599)	$357,524	$219,925
12	Federal Tax @ 35%	($15,392)	($32,769)	($48,161)	$125,184	$77,023
13	Current Federal Tax	($15,392)	($32,769)	($48,161)	$125,184	$77,023
14	ITC Adjustment					
15	Deferral	$0	$0	$0	$-0	$0
16	Restoration	1,885	(362)	1,523		1,523
17	Total ITC Adjustment	($1,885)	$362	($1,523)	$-0	($1,523)
18	Provision for Deferred Taxes	($15,272)	$39	($15,233)	$0	($15,233)
19	Total Income Tax	($35,763)	($39,948)	($75,711)	$150,662	$74,951

ORDER NO. 01-777

APPENDIX C

PORTLAND GENERAL ELECTRIC
Results of Operations
Twelve Months Ended December 31, 2002

30-Aug-01
08:58 AM

INPUT ASSUMPTIONS

COST OF CAPITAL - 2002	Capital Structure	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	$887,900	46.32%	7.51%	3.478%
Preferred Stock	$29,250	1.53%	8.43%	0.129%
Common Equity	$999,781	52.16%	10.50%	5.476%
Total	$1,916,931	100.00%		9.083%

REVENUE SENSITIVE COSTS	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00500
Taxes Other - Franchise	0.00000
- OPUC fee	0.00000
- Resource supplier	0.00000
State Taxable Income	0.99500
State Income Tax @ 6.6547%	0.06621
Federal Taxable Income	0.92879
Federal Income Tax @ 35%	0.32508
ITC	0.00000
Current FIT	0.32508
Other	0.00000
Total Excise Taxes	0.39129
Total Revenue Sensitive Costs	0.39629
Utility Operating Income	0.60371
Net-to-Gross Factor	1.65642

APPENDIX G
PAGE 4 OF 10

ORDER NO. 01-777

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
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		Miscellaneous Corrections to Company Filing								
		FERC Wholesale Fee (S-1)	Montana Production Tax (S-2)	Colstrip O & M (S-3)	Transmission O & M (S-4)	FERC Hydro Fee (S-5)	Income Tax Apportion (S-6)	Severance Program (S-7)	OAL Sale (S-8)	PGH Billings (S-9)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for Resale									
4	Other Operating Revenues									
5	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Operation & Maintenace									
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production O&M			$1,043		($14)			($83)	
9	Trojan O&M							$0		
10	Transmission O&M			$25	$0				($28)	
11	Distribution O&M				0				(223)	
12	Customer & MBC O&M									
13	Uncollectible Expense	0	0	0	0					
14	Administrative and General	(372)				714			108	(436)
15	Total Operation & Maintenance	($372)	$0	$1,068	$0	$700	$0	$0	($226)	($436)
16	Depreciation								(20)	
17	Amortization							$66	120	0
18	Property & Payroll Tax	0	0	0	0				0	
19	Franchise & Other Tax		450							
20	Utility Income Tax	147	(177)	(420)	0	(276)	0	(26)	55	172
21	Total Operating Expenses & Taxes	($225)	$273	$648	$0	$424	$0	$40	($71)	($264)
22	Net Operating Revenues	$225	($273)	($648)	($0)	($424)	$0	($40)	$71	$264
22	Average Rate Base									
23	Electric Plant in Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Accumulated Depreciation & Amortization								(60)	
25	Accumulated Deferred Income Taxes								(24)	
26	Accumulated Deferred Inv. Tax Credit									
27	Net Utility Plant	$0	$0	$0	$0	$0	$0	$0	($84)	$0
28	Net Trojan Investment									
29	Weatherization Investment									
30	Working Cash	(10)	12	29	0	19	0	2	(3)	(12)
31	Fuel									0
32	Materials & Supplies								0	
33	Other Deferred Debits								(355)	
34	Deferred Gains on Sales						0			
35	Other Deferred Credits									
36	Y2K Deferral									
37	Total Average Rate Base	($10)	$12	$29	$0	$19	$0	$2	($442)	($12)
	Revenue Requirement Effect	($374)	$454	$1,078	$0	$705	$0	$67	($184)	($439)

ORDER NO. 01-777

APPENDIX G

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
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		Miscellaneous Corrections to Company Filing								
		Retail Unbundling Allocation (S-10)	Beaver Turbine (S-11)	Other Revenue (S-12)	State Tax Credit (S-13)	Remove SERP Rate Base & MDCP Expense (S-14)	Remove Trojan (S-15)	Remove Neil (S-16)	Remove Other Debits & Credits (S-17)	Solar For Schools (S-18)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for Resale									
4	Other Operating Revenues			0				0	(589)	
5	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0	($589)	$0
6	Operation & Maintenace									
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production O&M									
9	Trojan O&M							$2,400		
10	Transmission O&M									
11	Distribution O&M									
12	Customer & MBC O&M	435								(55)
13	Uncollectible Expense									0
14	Administrative and General	303	0	0	0	(4,645)	0	$1,418		0
15	Total Operation & Maintenance	$738	$0	$0	$0	($4,645)	$0	$3,818	$0	($55)
16	Depreciation		182							
17	Amortization						(16,584)		(959)	0
18	Property & Payroll Tax		14							
19	Franchise & Other Tax									
20	Utility Income Tax	(290)	(116)	0	0	1,857	5,605	(1,603)	143	22
21	Total Operating Expenses & Taxes	$448	$80	$0	$0	($2,788)	($10,979)	$2,315	($816)	($33)
22	Net Operating Revenues	($448)	($80)	$0	$0	$2,788	$10,979	($2,315)	$227	$33
22	Average Rate Base									
23	Electric Plant in Service	$0	$3,200	$0	$0	$0	$0	$0	$0	$0
24	Accumulated Depreciation & Amortization		(278)							
25	Accumulated Deferred Income Taxes	0	0				30,413			
26	Accumulated Deferred Inv. Tax Credit		(133)				4,421			
27	Net Utility Plant	$0	$2,789	$0	$0	$0	$34,834	$0	$0	$0
28	Net Trojan Investment						(137,738)			
29	Weatherization Investment									
30	Working Cash	20	4	0	0	(124)	(490)	103	(36)	(1)
31	Fuel									
32	Materials & Supplies									
33	Other Deferred Debits								(7,811)	
34	Deferred Gains on Sales									
35	Other Deferred Credits					(2,122)			7,992	0
36	Y2K Deferral									
37	Total Average Rate Base	$20	$2,793	$0	$0	($2,246)	($103,394)	$103	$145	($1)
	Revenue Requirement Effect	$746	$553	$0	$0	($4,956)	($33,742)	$3,850	($354)	($55)

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
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		Miscellaneous Corrections to Company Filing								
		Salmon Springs Reclassification (S-19)	Green Power Purchase (S-20)	Property Tax Unbundling Correction (S-21)	Y2K Deferral (S-22)	Two Cities (S-23)	Miscellaneous Electric Revenues (S-24)	Remove Weather Option Cost (S-25)	Reduce Customer Acct. Non-Labor Exp. (S-26)	Category "A" Advertising Reduction (S-27)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for Resale									
4	Other Operating Revenues	183					998			
5	Total Operating Revenues	$183	$0	$0	$0	$0	$998	$0	$0	$0
6	Operation & Maintenace									
7	Net Variable Power Cost	$0	($420)	$0	$0	$129	$0	$0	$0	$0
8	Production O&M									
9	Trojan O&M									
10	Transmission O&M									
11	Distribution O&M									
12	Customer & MBC O&M								(1,600)	(2,358)
13	Uncollectible Expense									
14	Administrative and General	0	0	0	0	0	0	0	0	0
15	Total Operation & Maintenance	$0	($420)	$0	$0	$129	$0	$0	($1,600)	($2,358)
16	Depreciation									
17	Amortization									
18	Property & Payroll Tax									
19	Franchise & Other Tax									
20	Utility Income Tax	72	165	0	0	(52)	392	0	630	928
21	Total Operating Expenses & Taxes	$72	($255)	$0	$0	$77	$392	$0	($970)	($1,430)
22	Net Operating Revenues	$111	$255	$0	$0	($77)	$606	$0	$970	$1,430
22	Average Rate Base									
23	Electric Plant In Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Accumulated Depreciation & Amortization								0	
25	Accumulated Deferred Income Taxes									
26	Accumulated Deferred Inv. Tax Credit									
27	Net Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Net Trojan Investment									
29	Weatherization Investment									
30	Working Cash	3	(11)	0	0	3	17	0	(43)	(64)
31	Fuel									
32	Materials & Supplies									
33	Other Deferred Debits					96				
34	Deferred Gains on Sales									
35	Other Deferred Credits									
36	Y2K Deferral									
37	Total Average Rate Base	$3	($11)	$0	$0	$99	$17	$0	($43)	($64)
	Revenue Requirement Effect	($183)	($424)	$0	$0	$142	($1,001)	$0	($1,613)	($2,378)

ORDER NO. 01-777

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

	30-Aug-01 09:14 AM	Public Purpose Adjustment (S-28)	Reduce Marketing & Sales Expense (S-29)	Transmission & Distribution Exp. Reduction (S-30)	Reduce A & G Information Tech. Costs (S-31)	Remove Suppl. Executive Retirement Plan (S-32)	Bonus & Incentive Adjustment (S-33)	Workforce Level Adjustment (S-34)	OPUC Wage Formula Adjustment (S-35)	Distribution Plant Reduction (S-36)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$1,075
3	Sales for Resale									
4	Other Operating Revenues			(680)						0
5	**Total Operating Revenues**	$0	$0	($680)	$0	$0	$0	$0	$0	$1,075
6	Operation & Maintenace									
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production O&M									
9	Trojan O&M									
10	Transmission O&M			(1,505)						
11	Distribution O&M	0		(990)						
12	Customer & MBC O&M	(550)	(800)					(2,411)		
13	Uncollectible Expense									5
14	Administrative and General	(149)			(1,000)	(1,250)	(2,237)	(2,411)	(1,550)	
15	**Total Operation & Maintenance**	($699)	($800)	($2,495)	($1,000)	($1,250)	($2,237)	($4,822)	($1,550)	$5
16	Depreciation			0						(60)
17	Amortization									
18	Property & Payroll Tax					0	(240)	(518)	(167)	(30)
19.	Franchise & Other Tax									24
20	Utility Income Tax	275	315	715	394	492	983	2,116	680	473
21	**Total Operating Expenses & Taxes**	($424)	($485)	($1,780)	($606)	($758)	($1,494)	($3,224)	($1,037)	$413
22	**Net Operating Revenues**	$424	$485	$1,100	$606	$758	$1,494	$3,224	$1,037	$662
22	**Average Rate Base**									
23	Electric Plant in Service	$0	$0	$0	$0	$0	($602)	($1,046)	($336)	($2,000)
24	Accumulated Depreciation & Amortization				0	0				0
25	Accumulated Deferred Income Taxes				0					
26	Accumulated Deferred Inv. Tax Credit									
27	**Net Utility Plant**	$0	$0	$0	$0	$0	($602)	($1,046)	($336)	($2,000)
28	Net Trojan Investment									
29	Weatherization Investment									
30	Working Cash	(19)	(22)	(79)	(27)	(34)	(67)	(144)	(46)	18
31	Fuel									
32	Materials & Supplies									
33	Other Deferred Debits									
34	Deferred Gains on Sales									
35	Other Deferred Credits								0	
36	Y2K Deferral									
37	**Total Average Rate Base**	($19)	($22)	($79)	($27)	($34)	($669)	($1,190)	($382)	($1,982)
	Revenue Requirement Effect	($705)	($807)	($1,834)	($1,008)	($1,261)	($2,576)	($5,520)	($1,775)	($1,395)

ORDER NO. 01-777

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
09:14 AM

		Materials & Supplies Adjustment (S-37)	Y2K Amortization (S-38)	NEIL Amortization (S-39)	Accumulated Deferred Taxes (S-40)	Income Tax Adjustments (S-41)	Remove Property Sales Gains (S-42)	Depreciation Study Adj. (S-43)	SB 1149 Implementation Costs (S-44)	CIS/IT Disallowance Adjustments (S-45)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0.	$0	$0	$0	$0
3	Sales for Resale									
4	Other Operating Revenues									0
5	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Operation & Maintenece									
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production O&M									
9	Trojan O&M									
10	Transmission O&M									
11	Distribution O&M									
12	Customer & MBC O&M								376	
13	Uncollectible Expense									
14	Administrative and General								416	0
15	Total Operation & Maintenance	$0	$0	$0	$0	$0	$0	$0	$792	$0
16	Depreciation							(3,567)		0
17	Amortization		(1,977)	0		0	477		0	0
18	Property & Payroll Tax									0
19	Franchise & Other Tax									
20	Utility Income Tax	51	846	0	312	479	(188)	1,379	(318)	0
21	Total Operating Expenses & Taxes	$51	($1,131)	$0	$312	$479	$289	($2,188)	$474	$0
22	Net Operating Revenues	($51)	$1,131	$0	($312)	($479)	($289)	$2,188	($474)	$0
22	Average Rate Base									
23	Electric Plant in Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Accumulated Depreciation & Amortization					0		1,784	0	0
25	Accumulated Deferred Income Taxes				(22,832)	0				0
26	Accumulated Deferred Inv. Tax Credit									
27	Net Utility Plant	$0	$0	$0	($22,832)	$0	$0	$1,784	$0	$0
28	Net Trojan Investment									
29	Weatherization Investment									
30	Working Cash	2	(50)	0	14	21	13	(98)	21	0
31	Fuel									
32	Materials & Supplies	(3,681)		0						
33	Other Deferred Debits			0					459	
34	Deferred Gains on Sales									
35	Other Deferred Credits									
36	Y2K Deferral		(4,942)							
37	Total Average Rate Base	($3,679)	($4,992)	$0	($22,818)	$21	$13	$1,686	$480	$0
	Revenue Requirement Effect	($469)	($2,624)	$0	($2,916)	$797	$481	($3,371)	$857	$0

ORDER NO. 01-777

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

	30-Aug-01 09:00 AM	Franchise Fees (Base) (S-55)	Coyote Steam Sales (S-56)	Demand Exchange (PGE)	Weather Wise (PGE)	Load Forecast Revenue Update (PGE)	Additional Non-Power O & M Reduction (OPUC)	NVPC Forecast Additional (PGE)	Total Adjustments (Base Rates)
1	Operating Revenues								
2	Retail Sales	$0	$0	$0	$0	($33,917)	$0	$0	($32,842)
3	Sales for Resale								0
4	Other Operating Revenues	0	837	0	0	0	0	0	749
5	Total Operating Revenues	$0	$837	$0	$0	($33,917)	$0	$0	($32,093)
6	Operation & Maintenace								
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$117,278	$116,987
8	Production O&M								946
9	Trojan O&M								2,400
10	Transmission O&M								(1,508)
11	Distribution O&M								(1,213)
12	Customer & MBC O&M				(160)		(3,500)		(10,623)
13	Uncollectible Expense					(170)	0	0	(164)
14	Administrative and General	0	0	(100)	0	0	(3,426)	0	(14,617)
15	Total Operation & Maintenance	$0	$0	($100)	($160)	($170)	($6,926)	$117,278	$92,208
16	Depreciation	0	0	0	0	0	0	0	($3,465)
17	Amortization	0	0	0	0	0	0	0	(18,857)
18	Property & Payroll Tax	0	0	0	0	0	0	0	(941)
19	Franchise & Other Tax	794				(767)	0	0	502
20	Utility Income Tax	(313)	329	40	63	(12,961)	2,726	(46,164)	(39,948)
21	Total Operating Expenses & Taxes	$481	$329	($60)	($97)	($13,897)	($4,200)	$71,114	$29,498
22	Net Operating Revenues	($481)	$508	$60	$97	($20,020)	$4,200	($71,114)	($61,591)
22	Average Rate Base								
23	Electric Plant in Service	$0	$0	$0	$0	$0	$0	$0	($784)
24	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	1,446
25	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	7,557
26	Accumulated Deferred Inv. Tax Credit								4,288
27	Net Utility Plant	$0	$0	$0	$0	$0	$0	$0	$12,507
28	Net Trojan Investment								(137,738)
29	Weatherization Investment								0
30	Working Cash	21	15	(3)	(4)	(620)	(187)	3,172	1,315
31	Fuel								0
32	Materials & Supplies								(3,681)
33	Other Deferred Debits								(7,611)
34	Deferred Gains on Sales								0
35	Other Deferred Credits								5,870
36	Y2K Deferral								(4,942)
37	Total Average Rate Base	$21	$15	($3)	($4)	($620)	($187)	$3,172	($134,281)
	Revenue Requirement Effect	$800	($839)	($100)	($161)	$33,068	($6,985)	$118,272	$81,820

ENCLOSURE III TO VPN-002-2005

OPUC ORDER NO. 03-528, ENTERED AUGUST 26, 2003, IN DOCKET UE 147

ORDER NO. **03-528**

ENTERED AUG 26 2003

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 147

In the Matter of	)	
	)	
PACIFIC POWER & LIGHT (dba PACIFICORP)	)	ORDER
	)	
Application for Approval of Revised Tariffs; Advice No. 03-003.	)	

DISPOSITION: STIPULATION ADOPTED; DOCKET CLOSED

On March 18, 2003, PacifiCorp filed a request for a general rate increase in the company's annual Oregon based revenues of $57,909,063, or 7.4 percent overall. PacifiCorp based its filing on a normalized future test year ending March 2004.

In July 2003, pursuant to the schedule adopted in this docket, parties convened for settlement discussions. Settlement discussions were open to all parties. Parties reached a global settlement on all matters related to the docket. On August 18, 2003, parties submitted a joint stipulation detailing their settlement agreement. The stipulation was signed by PacifiCorp; Commission Staff; the Citizens' Utility Board; Industrial Customers of Northwest Utilities; and Fred Meyer Stores and Quality Food Centers, Divisions of The Kroger Co. (the stipulating parties). The net effect of the stipulation is an average overall revenue requirement increase of $8.5 million or 1.1 percent. The stipulating parties submitted joint testimony and exhibits in support of the stipulation.

On August 21, 2003, parties convened for a hearing on the stipulation. The stipulation, testimony, and exhibits accompanying both were entered into evidence, as were the testimony and exhibits filed as PacifiCorp's direct case. Counsel for PacifiCorp represented that all parties to this docket had reviewed the stipulation and had either signed it or indicated they had no objection to its implementation.

We have reviewed the stipulation, the testimony, and the supporting exhibits. We find that the stipulation is a fair and reasonable resolution of all issues in this docket. The stipulation, its Attachments A and B, and the stipulating parties' Exhibit 106, are attached to this order as Appendix A and incorporated herein. Exhibit 106 contains several schedules that summarize the stipulated revenue requirement adjustments from PacifiCorp's filed case in this docket. Page 1 replicates Attachment A to the stipulation and is not included. Pages 2 through 3 represent the stipulated adjustments and assumptions for the test period (the 12 months ending March 31, 2004). Page 4 contains the rate of return and revenue sensitive costs. Pages 5 through 8 show the revenue, expense, and rate base changes associated with each adjustment. Except as specifically set forth in the adjustments, PacifiCorp's initial revenue requirement and all its components are accepted as filed.

We conclude that the stipulation should be adopted with an effective date of September 1, 2003.

ORDER

IT IS ORDERED that:

1. The stipulation filed by PacifiCorp; Commission Staff; Citizens' Utility Board; Industrial Customers of Northwest Utilities; and Fred Meyer Stores and Quality Food Centers, Divisions of The Kroger Co., is adopted.

2. Advice No. 03-003, filed by PacifiCorp on March 18, 2003, is permanently suspended.

3. PacifiCorp shall file tariffs consistent with the findings and conclusions contained in this order to be effective no later than September 1, 2003.

Made, entered, and effective AUG 26 2003.

Roy Hemmingway

Roy Hemmingway
Chairman

Lee Beyer

Lee Beyer
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

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 to a court pursuant to applicable law.

APPENDIX A

THE PUBLIC UTILITY COMMISSION OF OREGON

UE 147

In the Matter of

PACIFICORP's

Application for Approval of Revised Tariff Schedules (UE 147)

STIPULATION

PARTIES

1. The Parties to this Stipulation are PacifiCorp (or the "Company"), the Staff of the Public Utility Commission of Oregon ("Staff"), the Industrial Customers of Northwest Utilities ("ICNU"), the Citizens' Utility Board ("CUB"), and Fred Meyer Stores and Quality Food Centers, Divisions of The Kroger Co. ("Kroger") (together the "Parties"). Natural Resources Defense Counsel ("NRDC"), Renewable Northwest Project ("RNP"), Northwest Energy Coalition ("NWEC"), and Portland General Electric ("PGE") are not parties to this Stipulation but do not oppose approval of the Stipulation to resolve all issues in this case.

BACKGROUND

2. On March 18, 2003, PacifiCorp filed revised tariff schedules to effect a $57.9 million increase in its base prices to Oregon electric consumers, which was an overall 7.4 percent increase in its base prices. PacifiCorp based its filing on a normalized future test year ending March 2004.

3. On July 7, 2003, the Staff served on all Parties its report of issues and proposed adjustments to PacifiCorp's revenue requirement filing. The Staff's report was provided for settlement purposes only.

4. Pursuant to Administrative Law Judge Ruth Crowley's Prehearing Conference Memorandum, settlement discussions commenced on July 14, 2003, and continued on July 18, 21,

22, and 30, 2003. The settlement discussions were open to all parties. As a result of the settlement conferences, the Parties to this Stipulation have reached a global settlement on all matters related to this Docket. The net effect of the Stipulation is an average overall revenue requirement increase of $8.5 million or 1.1 percent. The Parties submit this Stipulation to the Commission and respectfully request that the Commission approve the Stipulation as presented.

AGREEMENT

5. Revenue Requirement: The Parties to this Stipulation agree that PacifiCorp will reduce its revenue requirement request to reflect the adjustments listed on Attachment A to this Stipulation. In summary, PacifiCorp's original filing supported a revenue requirement increase of $57.9 million. The adjustments listed on Attachment A reduce this amount by approximately $49.4 million. With respect to the Company's net power costs, the adjustments reduce the Company's filed net power costs by approximately $13 million on a Total Company basis to $598 million. With respect to the Company's pension costs, the adjustment reduces it to the Company's forecasted Oregon allocated FY 2004 FAS 87 pension expense, $16,300,000, a reduction of $5,605,000 from the Company's filing, which was based on an average of forecasted expense between FY 2004 and FY 2008.

The Parties agree that the stipulated revenue requirement can be derived from an overall rate of return based on the following capital structure and capital costs:

	Ratio	Cost	Weighted Cost
Long-Term Debt	47.61%	6.48%	3.085%
Preferred Stock	6.39%	5.75%	0.367%
Common Equity	46.00%	10.50%	4.830%
TOTAL			8.283%

6. Depreciation: The Parties agree that the Company's new depreciation rates adopted in UM 1064 should be implemented in this case, lowering the Company's filed revenue requirement by $8,020,000

7. Allocation Methodology: The Parties understand that PacifiCorp is working to develop a comprehensive resolution to its interjurisdictional allocation issues.

The Modified Accord method was not used in determining this Stipulation and there is no agreement that the Modified Accord is the appropriate allocation method for this case. In this Stipulation, the Parties agree that the costs associated with seasonal CTs such as West Valley and Gadsby should be allocated under a different methodology that better assigns the costs of meeting summer load to the states that contribute to that load. Thus, Oregon's allocated cost of those resources is reduced by $2 million and that reduction is reflected in the $8.5 million revenue requirement increase in this Stipulation.

The Company commits to making a filing with the Commission by December 31, 2003, that will address interjurisdictional allocation, as contemplated by PacifiCorp's Multi-State Process. In that proceeding, no Party shall be bound to any allocation methodology as a result of this Stipulation.

8. West Valley-UE 134 Reconsideration Proceedings/UI 196 Appeal: ICNU, Staff, CUB and the Company agree that Docket UE 134 should be closed without further Commission action. In addition, ICNU agrees to withdraw its appeal of the Commission order No. 02-361, now pending in Marion County Circuit Court, Case No. 02C16369. The Parties agree that, as a result of the withdrawal of these cases, no Party is collaterally estopped in the future from challenging the prudency of the West Valley plant, arguing that it should be included in the Company's revenue requirement at market prices rather than at cost or raising other issues related to the West Valley plant, other than those related to the affiliated interests issues resolved in UI 196.

9. Accounting Practices: PacifiCorp will work with the Parties to identify opportunities for improvement in the FERC accounting data provided by the Company in its general rate case filings.

At the conclusion of this Docket, the Parties will meet to review the Company's FERC accounts. PacifiCorp commits to direct its external, independent auditor to perform an audit review and provide a copy of the audit report to the Parties to confirm compliance with FERC accounting rules in the first quarter of FY 2005.

10. Future General Rate Case Filings: PacifiCorp agrees that it will not file a General Rate Case ("GRC") sooner than August 31, 2004, and that PacifiCorp will base its next GRC filing on test year data that incorporates the improvements and changes resulting from the process set forth in the previous paragraph. The Parties agree that, if necessary to comply with this provision, the Company may reclassify historical accounting data to be utilized in its next GRC.

11. Centralia Credit: The Parties agree that as of the effective date of this Stipulation, the Centralia credit will be increased by $7 million annually from approximately $18 million to approximately $25 million so that the credit is amortized over approximately the five-year period beginning January 1, 2001, and ending December 31, 2005.

12. Merger Credits: The Parties agree that the offsettable ScottishPower merger credit will be eliminated as of the effective date of this Stipulation. The Parties agree that the non-offsettable merger credit will be reduced to a $4 million annual amount, and will be amortized to return the full amount to customers by December 31, 2004.

13. Schedule 199: The Company agrees to implement a new schedule, Schedule 199, as of the effective date of this Stipulation, to return the gain to consumers from the sale of the Halsey service territory and Albina print shop. Schedule 199 will result in an approximate $2.8 million credit amortized over approximately a one-year period.

14. Service Quality Measures: The Service Quality Measures as adopted in UE 94 per Order No. 98-191, including all modifications adopted by the Commission and as modified in Docket UM 918 per Order No. 99-616, shall be extended from its current expiration date of March 31, 2010, to March 31, 2014 (i.e., 10 full reporting years following the current reporting year). This extension does not include Merger Performance Standards and Customer Guarantees. As allowed in the SQM agreement, Merger Modifications dated June 16, 1999, under Section G.2,

Special Provisions, the Company or other parties may request the Commission make modifications to the agreement during the term of the plan.

15 GRID: The Company, Staff, and interested consumer groups will work together to update the Generation and Regulation Initiatives Decision Tools ("GRID") hydro model. The Company agrees to implement changes agreed to by all Parties in PacifiCorp's next GRC.

16. Rate Spread and Design: PacifiCorp agrees that it will not increase the Residential Basic Charge. The Parties agree that the Rate Spread will result in an equal percent increase to base rates for the major customer classes and that no customer class will receive more than 2 times the average net increase, but that within a customer class, rate spread may be adjusted based on cost of service. The Parties agree that revenue obligations of the various customer classes resulting from this Stipulation shall be spread among the classes in the manner described in Attachment B to this Stipulation. This change in the Rate Spread will result in a reduction in the Rate Mitigation Adjustment in Schedule 299. The Parties agree to this Rate Spread in order to move closer to the eventual elimination of Schedule 299.

17. New Commercial Schedule: PacifiCorp, Staff, Kroger, and any interested consumer and consumer group will work to develop a new schedule to cover large nonresidential consumers under 1 MW.

GENERAL PROVISIONS

18. The Parties agree that this Stipulation is in the public interest and results in an overall fair, just and reasonable outcome.

19. The Parties agree that expedited consideration of this Stipulation is warranted. The Stipulation will be offered into the record of the proceeding as evidence pursuant to OAR 860-14-0085. The Parties agree to use best efforts to prepare and submit the Stipulation and supporting materials to the Commission in time to permit the Commission to put rates into effect by September 1, 2003. The Parties shall support adoption of the Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor the Stipulation at the hearing and

recommend that the Commission issue an order on an expedited basis adopting the settlements contained herein.

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

21. If the Stipulation is challenged by any other party to this proceeding, the Parties to the Stipulation reserve the right to cross-examine witnesses and put on such case 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 the Stipulation.. Notwithstanding this reservation of rights, the Parties to the Stipulation agree that they will continue to support the Commission's adoption of the terms of the Stipulation.

22. The Parties have negotiated the Stipulation as an integrated document. If the Commission rejects all or any material portion of the Stipulation or imposes additional material conditions in approving the Stipulation, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

23. 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 specifically noted in this Stipulation. No party shall be deemed to have agreed that any paragraph of this Stipulation is appropriate for resolving issues in any other proceeding except for ongoing commitments specifically noted in paragraphs 7, 8, 9, 10, 14 and 15 of this Stipulation.

24 This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

///

This Stipulation is entered into by each party on the date entered below such party's signature.

DATED: August ____, 2003

PACIFICORP

By: ______________________

Date: August 18, 2003

STAFF OF THE OREGON
PUBLIC UTILITY COMMISSION

By: ______________________

Date: ______________________

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

FRED MEYER STORES AND
QUALITY FOOD CENTERS,
DIVISIONS OF THE KROGER COMPANY

By: ______________________

Date: ______________________

This Stipulation is entered into by each party on the date entered below such party's signature.

DATED: August ____, 2003

PACIFICORP

By: ______________________

Date: ______________________

STAFF OF THE OREGON
PUBLIC UTILITY COMMISSION

By: ______________________

Date: ______________________

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD

By: Robt Jenks

Date: 8-15-03

FRED MEYER STORES AND
QUALITY FOOD CENTERS,
DIVISIONS OF THE KROGER COMPANY

By: ______________________

Date: ______________________

This Stipulation is entered into by each party on the date entered below such party' signature.

DATED: August 18th, 2003

PACIFICORP

By: ____________________

Date: ____________________

STAFF OF THE OREGON PUBLIC UTILITY COMMISSION

By: ____________________

Date: ____________________

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

By: ____________________

Date: ____________________

CITIZENS' UTILITY BOARD

By: ____________________

Date: ____________________

FRED MEYER STORES AND QUALITY FOOD CENTERS, DIVISIONS OF THE KROGER COMPANY

By: Michael L. Kurtz

Date: 8/18/03

This Stipulation is entered into by each party on the date entered below such party's signature.

DATED: August 18, 2003

PACIFICORP

By: ______________________

Date: ______________________

STAFF OF THE OREGON
PUBLIC UTILITY COMMISSION

By: ______________________

Date: 8/18/03

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

By: ______________________

Date: ______________________

CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

FRED MEYER STORES AND
QUALITY FOOD CENTERS,
DIVISIONS OF THE KROGER COMPANY

By: ______________________

Date: ______________________

This Stipulation is entered into by each party on the date entered below such party's signature.

DATED: August 18th, 2003

PACIFICORP	STAFF OF THE OREGON PUBLIC UTILITY COMMISSION
By: ______	By: ______
Date: ______	Date: ______
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES	CITIZENS' UTILITY BOARD
By: ______	By: ______
Date: August 18, 2003	Date: ______
FRED MEYER STORES AND QUALITY FOOD CENTERS, DIVISIONS OF THE KROGER COMPANY	
By: ______	
Date: ______	

Attachment A

PACIFICORP - OREGON
Issues Summary
UE 147 - March 2004 Test Year
($000)

Item	Issue	Revenue Requirement Effect 2004
	Revenue Requirement on the Company's Filed Results	$57,909
	Adjustments (Base Rates)	
S-0	Rate of Retum	(14,756)
S-1	(Included in S-31/I-5)	-
S-2	(Included in S-31/I-5)	-
S-3	Steam Revenue from IMC/Kalium	(617)
S-4	Forfeited Discounts and Interest	0
S-5	Rent from Electric Property (Account 454)	(1,799)
S-6	Other Electric Revenues (Account 456.12)	73
S-7	Wheeling Revenues	0
S-8	MCI Fog Wire Revenues	(990)
S-9	(Included in S-31/I-5)	-
S-10	Kennecott Generation Incentive	0
S-11	Steam Generation Maintenance Expense	1,645
S-12	Postage	(78)
S-13	Incentive Programs	(2,695)
S-14	FAS 87 Pension Expense	(5,605)
S-15	Property Insurance, Injuries & Damages	(791)
S-16	Audit of FERC Accounting Anomalies	0
S-17	Outside Services	(2,897)
S-18	Economic Development Labor	0
S-19	EEI Memberships	(141)
S-20	Remove A&G Costs Paid to ScottishPower	(1,645)
S-21	Remove A&G Affiliated Interest Costs	(129)
S-22	Remove A&G Costs Associated with UK Personnel	(726)
S-23	Depreciation	(8,020)
S-24	Amortization	(655)
S-25	FIT and SIT Adjustment	(2,406)
S-26	Remove Mill Fork Coal Lease	0
S-27	Information Technology additions	0
S-*	Revenue Sensitive Costs	(723)
P-1	Trail Mountain Double Count	(1,099)
S-31, I-5	Miscellaneous Power Cost Issues	(2,955)
I-7, C-1	Reallocate West Valley and Gadsby CTs	(2,000)
I-8	Hunter Insurance Payment	(400)
	Total Adjustments (Base Rates)	(49,409)
	Total Revenue Requirements Change (Base Rates)	$8,500

Attachment B

PACIFIC POWER & LIGHT COMPANY
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED MARCH 31, 2004

TABLE A

					Present Revenues ($000)			Proposed Revenues ($000)			Change			
											Base Rates		Net Rates	
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%	($000)	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)
	Residential													
1	Residential	4	438,767	5,207,242	$392,821	$3,422	$396,243	$397,114	$5,332	$402,446	$4,293	1.1%	$6,203	1.6%
	Commercial & Industrial													
2	Outdoor Area Lighting Service	15	8,245	13,269	$1,295	$77	$1,372	$1,309	$63	$1,372	$14	1.1%	$0	0.0%
3	Recreational Field Lighting	54	101	843	$72	$4	$76	$72	$4	$76	*	0.0%	$0	0.0%
4	Gen. Svc. < 31 kW	23	67,531	1,015,878	$67,955	$5,835	$73,790	$69,070	$4,720	$73,790	$1,115	1.6%	$0	0.0%
5	Gen. Svc. 31 - 200 kW	28	9,131	1,999,399	$112,011	$11,139	$123,150	$113,305	$9,844	$123,149	$1,294	1.2%	($1)	0.0%
6	Gen. Svc. 201 - 999 kW	30	795	1,248,708	$61,365	$6,665	$68,030	$61,608	$6,431	$68,039	$243	0.4%	$9	0.0%
	Overall Sch 23/28/30		77,457	4,263,985	$241,331	$23,639	$264,970	$243,983	$20,995	$264,978	$2,652	1.1%	$8	0.0%
7	Large General Service >= 1,000 kW	48	226	3,512,549	$128,080	$16,953	$145,033	$129,468	$15,550	$145,018	$1,388	1.1%	($15)	0.0%
8	Partial Req. Svc. < 1,000 kW	36	2	90	$37	$0	$37	$37	$0	$37	*	0.0%	$0	0.0%
9	Partial Req. Svc. >= 1,000 kW	47	6	108,130	$4,106	$344	$4,450	$4,150	$300	$4,450	$44	1.1%	$0	0.0%
10	Agricultural Pumping Service	41	6,360	107,619	$9,409	($1,783)	$7,626	$9,512	($1,762)	$7,750	$103	1.1%	$124	1.6%
11	Agricultural Pumping - Other	--	2,073	107,761	$744	$0	$744	$744	$0	$744	$0	0.0%	$0	0.0%
12	**Total Commercial & Industrial**		94,470	8,114,246	$385,074	$39,234	$424,308	$389,275	$35,150	$424,425	$4,201	1.1%	$117	0.0%
	Public Street Lighting													
13	Street Lighting Service	50	327	11,772	$947	$65	$1,012	$958	$54	$1,012	$11	1.2%	$0	0.0%
14	Street Lighting Service HPS	51	662	20,306	$2,700	$127	$2,827	$2,730	$97	$2,827	$30	1.1%	$0	0.0%
15	Street Lighting Service	52	110	1,980	$201	$11	$212	$203	$9	$212	$2	1.0%	$0	0.0%
	Street Lighting Service	53	216	7,776	$352	$38	$390	$356	$34	$390	$4	1.1%	$0	0.0%
	Total Public Street Lighting		1,315	41,834	$4,200	$241	$4,441	$4,247	$194	$4,441	$47	1.1%	$0	0.0%
18	**Total Sales to Ultimate Consumers**		534,552	13,363,322	$782,095	$42,897	$824,992	$790,636	$40,676	$831,312	$8,541	1.1%	$6,320	0.8%
	Employee Discount				($402)	($4)	($406)	($407)	($5)	($412)	($5)		($6)	
20	**Total Sales with Employee Discount**				$781,693	$42,893	$824,586	$790,229	$40,671	$830,900	$8,536	1.1%	$6,314	0.8%

ORDER NO. 03-528

APPENDIX
PAGE 15 OF 22

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[1] Excludes effects of the BPA Energy Discount (Schedule 98), Low Income Bill Payment Assistance Charge (Schedule 91) and Public Purpose Charge (Schedule 290).

* Less than $500.

UE 147 Final Settlement Case

PACIFICORP - UE 147
Oregon Allocated Results of Operations
Twelve Months Ended March 31, 2004
($000)

08-Aug-03
08:10 AM

		2004 Results Per Company Filing (1)	Adjustments (2)	2004 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	**Operating Revenues**					
2	Retail Sales	$787,627	$0	787,627	$8,500	$796,127
3	Wholesale Sales	200,529	522	201,051	0	201,051
4	Other Revenues	21,654	3,252	24,906	0	24,906
5	Total Operating Revenues	$1,009,810	$3,774	$1,013,584	$8,500	$1,022,084
6	**Operating Expenses**					
7	Steam Production	$188,624	($3,249)	$185,375	$0	$185,375
8	Hydro Production	12,669	0	12,669	0	12,669
9	Other Power supply	225,454	(522)	224,932	0	224,932
10	Transmission	30,473	0	30,473	0	30,473
11	Distribution	45,829	0	45,829	0	45,829
12	Customer Accounting	27,806	0	27,806	31	27,837
13	Customer Service & Info	1,257	0	1,257	0	1,257
14	Sales	0	0	0	0	0
15	Administrative and General	83,101	(14,295)	68,807	0	68,807
16	Total Operation & Maintenance	$615,213	($18,066)	$597,148	$31	$597,179
17	Depreciation	116,595	(8,790)	107,805	0	107,805
18	Amortization	19,238	(676)	18,562	0	18,562
19	Taxes Other than Income	48,762	0	48,762	186	48,948
20	Income Taxes	60,628	11,256	71,884	3,148	75,032
21	Miscellaneous Revenue and Expense	(157)	0	(157)	0	(157)
22	Total Operating Expenses	$860,279	($16,276)	$844,003	$3,365	$847,368
23	**Net Operating Revenues**	$149,531	$20,050	$169,581	$5,136	$174,716
24	**Average Rate Base**					
25	Electric Plant In Service	$3,871,698	($706)	$3,870,992	$0	$3,870,992
26	Accumulated Depreciation & Amortization	(1,653,777)	(555)	(1,654,332)	0	(1,654,332)
27	Accumulated Deferred Income Taxes	(228,750)	(974)	(229,724)	0	(229,724)
28	Accumulated Deferred Inv. Tax Credit	(11,519)	0	(11,519)	0	(11,519)
29	Net Utility Plant	$1,977,652	($2,235)	$1,975,417	$0	$1,975,417
30	Plant Held for Future Use	0	0	0	0	0
31	Acquisition Adjustments	29,122	0	29,122	0	29,122
32	Working Capital	17,857	(338)	17,519	41	17,560
33	Fuel Stock	15,122	0	15,122	0	15,122
34	Materials & Supplies	24,037	0	24,037	0	24,037
35	Customer Adv for Const	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0
37	Prepayments	6,302	0	6,302	0	6,302
38	Misc. Deferred Debits	67,219	0	67,219	0	67,219
39	Misc. Rate Base Additions/(Deductions)	(22,352)	(2,839)	(25,191)	0	(25,191)
40	Total Average Rate Base	$2,114,969	($5,412)	$2,109,547	$41	$2,109,588
41	Rate of Return	7.07%		8.04%		8.28%
42	Implied Return on Equity	7.90%		9.97%		10.50%

ORDER NO. 03-528

08-Aug-03
07:58 AM

PACIFICORP - OREGON
Oregon Allocated Results of Operations
Twelve Months Ended March 31, 2004
($000)

	Income Tax Calculations	2004 Per Company Filing (1)	Adjustments (2)	2004 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$1,009,810	$3,774	$1,013,584	$8,500	$1,022,084
2	Book Expenses Other than Depreciation	683,056	(18,742)	664,315	217	664,532
3	State Tax Depreciation	116,595	(8,790)	107,805		107,805
4	Interest	66,688	(167)	66,521	1	66,522
5	Schedule M Differences	(11,064)	8,014	(3,050)		(3,050)
6	State Taxable Income	$154,535	$23,458	$177,993	$8,282	$186,275
7	Add OR Depletion Adjustment - Net	$680				
8	Total State Taxable Income	$155,215				
9	State Income Tax @ 4.619% Staff (6.6% Company)	$10,244	($1,923)	$8,321	$383	$8,704
10	Net State Income Tax	$10,244	($1,923)	$8,321	$383	$8,704
11	Additional Tax Depreciation	0	0	0	0	0
12	Other Schedule M Differences	680	0	680	0	680
13	Federal Taxable Income	$144,291	$25,381	$169,672	$7,899	$177,571
14	Federal Tax @ 35%	$50,502	$9,389	$59,891	$2,765	$62,656
15	Wind Power Tax Credits	0	0	0	0	0
16	Current Federal Tax	$50,502	$9,389	$59,891	$2,765	$62,656
17	PMI	$0	$0	$0	$0	$0
18	ITC Adjustment					
19	Deferral	$0	$0	$0	$-0	$0
20	Restoration	0	0	0	0	0
21	Total ITC Adjustment	$0	$0	$0	$0	$0
22	Provision for Deferred Taxes	($118)	$3,790	$3,672	$0	$3,672
23	Total Income Tax	$60,628	$11,256	$71,884	$3,148	$75,032

08-Aug-03
08:10 AM

PACIFICORP - OREGON
Oregon Allocated Results of Operations
Twelve Months Ended March 31, 2004

INPUT ASSUMPTIONS

COST OF CAPITAL - 2004	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	47.61%	6.480%	3.085%
Preferred Stock	6.39%	5.750%	0.367%
Common Equity	46.00%	10.500%	4.830%
Total	100.00%		8.282%

REVENUE SENSITIVE COSTS	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00367
Taxes Other - Franchise	0.02138
- Other	0.00000
- Resource supplier	0.00056
State Taxable Income	0.97439
State Income Tax @ 4.619%	0.04501
Federal Taxable Income	0.92938
Federal Income Tax @ 35%	0.32528
ITC	0.00000
Current FIT	0.32528
Other	0.00000
Total Excise Taxes	0.37029
Total Revenue Sensitive Costs	0.39590
Utility Operating Income	0.60410
Net-to-Gross Factor	1.65536

PACIFICORP - OREGON
Adjustments to Oregon Allocated Results
UE 147 Test Year Ending March 2004
($000)

	08-Aug-03 08:10 AM	Extrinsic Value of Resources [incl. in S-31/I-5] (S-1)	Margin Adjustment (incl. in S-31/I-5] (S-2)	Steam Revenue from IMC/Kalium (S-3)	Forfeited Discounts & Interest (S-4)	Rent from Electric Property (S-5)	Other Elec Revenues Acct 456.12 (S-6)	Wheeling Revenues Adjustment (S-7)	MCI Fog Wire Revenue Adjustment (S-8)	Aquila Hydro Hedge [incl. in S-31/I-5] (S-9)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0							
4	Other Revenues			602	0	1,755	(71)	0	966	
5	Total Operating Revenues	$0	$0	$602	$0	$1,755	($71)	$0	$966	$0
6	Operating Expenses									
7	Steam Production	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Hydro Production									
9	Other Power Supply		$0							$0
10	Transmission									
11	Distribution									
12	Customer Accounting									
13	Customer Service & Info									
14	Sales									
15	Administrative and General									
16	Total Operation & Maintenance	$0	$0	$0	$0	$0	$0	$0	$0	$0
17	Depreciation									
18	Amortization									
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0
20	Income Taxes	0	0	229	0	667	(27)	0	367	0
21	Miscellaneous Revenue and Expense								0	
22	Total Operating Expenses	$0	$0	$229	$0	$667	($27)	$0	$367	$0
23	Net Operating Revenues	$0	$0	$373	$0	$1,088	($44)	$0	$599	$0
24	Average Rate Base									
25	Electric Plant In Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Accumulated Depreciation & Amortization									
27	Accumulated Deferred Income Taxes									
28	Accumulated Deferred Inv. Tax Credit									
29	Net Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Plant Held for Future Use									
31	Acquisition Adjustments									
32	Working Capital	0	0	5	0	14	(1)	0	8	0
33	Fuel Stock									
34	Materials & Supplies									
35	Customer Adv for Const									
36	Weatherization Loans									
37	Prepayments									
38	Misc. Deferred Debits									
39	Misc. Rate Base Additions/(Deductions)									
40	Total Average Rate Base	$0	$0	$5	$0	$14	($1)	$0	$8	$0
41	Revenue Requirement Effect	$0	$0	($617)	$0	($1,799)	$73	$0	($990)	$0

ORDER NO. 03-528

APPENDIX
PAGE 19 OF 22

PACIFICORP - OREGON
Adjustments to Oregon Allocated Results
UE 147 Test Year Ending March 2004
($000)

	08-Aug-03 08:10 AM	Kennecott Generation Incentive (S-10)	Steam Maintenance Expense (S-11)	Postage Adjustment (S-12)	Incentive Programs Adjustment (S-13)	FAS 87 Pension Expense (S-14)	Property Insur Injury & Damages Adjustment (S-15)	Accounting Anomolies Adjustment (S-16)	Outside Services Adjustment (S-17)	Economic Development Labor (S-18)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales									
4	Other Revenues									
5	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Operating Expenses									
7	Steam Production	$0	$1,600	$0	$0	$0	$0	$0	$0	$0
8	Hydro Production									
9	Other Power Supply	$0								
10	Transmission									
11	Distribution									
12	Customer Accounting									
13	Customer Service & Info									
14	Sales									
15	Administrative and General			(77)	(2,541)	(5,453)	(835)	0	(2,819)	$0
16	Total Operation & Maintenance	$0	$1,600	($77)	($2,541)	($5,453)	($835)	$0	($2,819)	$0
17	Depreciation									
18	Amortization									
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0
20	Income Taxes	0	(608)	30	974	2,073	311	0	1,072	0
21	Miscellaneous Revenue and Expense									
22	Total Operating Expenses	$0	$992	($47)	($1,567)	($3,380)	($524)	$0	($1,747)	$0
23	Net Operating Revenues	$0	($992)	$47	$1,567	$3,380	$524	$0	$1,747	$0
24	Average Rate Base									
25	Electric Plant in Service	$0	$0	$0	($706)	$0	$0	$0	$0	$0
26	Accumulated Depreciation & Amortization									
27	Accumulated Deferred Income Taxes			0	0					
28	Accumulated Deferred Inv. Tax Credit									
29	Net Utility Plant	$0	$0	$0	($706)	$0	$0	$0	$0	$0
30	Plant Held for Future Use									
31	Acquisition Adjustments									
32	Working Capital	0	21	(1)	(33)	(70)	(11)	0	(36)	0
33	Fuel Stock									
34	Materials & Supplies									
35	Customer Adv for Const									
36	Weatherization Loans									
37	Prepayments									
38	Misc. Deferred Debits									
39	Misc. Rate Base Additions/(Deductions)						564			
40	Total Average Rate Base	$0	$21	($1)	($739)	($70)	$653	$0	($36)	$0
41	Revenue Requirement Effect	$0	$1,645	($78)	($2,695)	($5,605)	($791)	$0	($2,897)	$0

ORDER NO. 03-528

APPENDIX
PAGE 20 OF 22

PACIFICORP - OREGON
Adjustments to Oregon Allocated Results
UE 147 Test Year Ending March 2004
($000)

	04-Aug-03 08:10 AM	Memberships Adjustment (S-19)	Remove ScottishPower A&G Costs (S-20)	A&G Affiliated Interest Adjustment (S-21)	Remove UK Personnel Costs (S-22)	Depreciation Adjustment (S-23)	Amortization Adjustment (S-24)	FIT & SIT Adjustment (S-25)	Remove Mill Fork Coal Lease (S-26)	Info technology Plant Additions (S-27)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales									
4	Other Revenues									
5	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Operating Expenses									
7	Steam Production	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Hydro Production									
9	Other Power Supply									
10	Transmission									
11	Distribution									
12	Customer Accounting									
13	Customer Service & Info									
14	Sales									
15	Administrative and General	(137)	(1,600)	(126)	(707)	0	0	0	0	0
16	**Total Operation & Maintenance**	($137)	($1,600)	($126)	($707)	$0	$0	$0	$0	$0
17	Depreciation					(8,790)				
18	Amortization						(676)			0
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0
20	Income Taxes	52	608	48	269	4,108	253	(1,451)	0	0
21	Miscellaneous Revenue and Expense	0								
22	**Total Operating Expenses**	($85)	($992)	($78)	($438)	($4,682)	($423)	($1,451)	$0	$0
23	**Net Operating Revenues**	$85	$992	$78	$438	$4,682	$423	$1,451	$0	$0
24	**Average Rate Base**									
25	Electric Plant in Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Accumulated Depreciation & Amortization					(893)	338			0
27	Accumulated Deferred Income Taxes					(974)				
28	Accumulated Deferred Inv. Tax Credit									
29	**Net Utility Plant**	$0	$0	$0	$0	($1,867)	$338	$0	$0	$0
30	Plant Held for Future Use									
31	Acquisition Adjustments									
32	Working Capital	(2)	(21)	(2)	(9)	(97)	(9)	(30)	0	0
33	Fuel Stock									
34	Materials & Supplies									
35	Customer Adv for Const									
36	Weatherization Loans									
37	Prepayments									
38	Misc. Deferred Debits								0	
39	Misc. Rate Base Additions/(Deductions)								0	
40	**Total Average Rate Base**	($2)	($21)	($2)	($9)	($1,964)	$329	($30)	$0	$0
41	**Revenue Requirement Effect**	($141)	($1,645)	($129)	($726)	($8,020)	($655)	($2,406)	$0	$0

ORDER NO. 03-528

APPENDIX
PAGE 21 OF 22

PACIFICORP - OREGON
Adjustments to Oregon Allocated Results
UE 147 Test Year Ending March 2004
($000)

	08-Aug-03 08:10 AM	Trail Mountain Double Count (P-1)	Miscellaneous Power Cost Issues (S-31, I-5)	Reallocate West Valley & Gadsby CTs (I-7, C-1)	Hunter Insurance Payment (I-8)	Total Adjustments (Base Rates)
1	Operating Revenues					
2	Retail Sales	$0	$0	$0	$0	$0
3	Wholesale Sales		522			522
4	Other Revenues					3,252
5	Total Operating Revenues	$0	$522	$0	$0	$3,774
6	Operating Expenses					
7	Steam Production	($1,070)	($1,833)	($1,946)	$0	($3,249)
8	Hydro Production					0
9	Other Power Supply		($522)			(522)
10	Transmission					0
11	Distribution					0
12	Customer Accounting					0
13	Customer Service & Info					0
14	Sales					0
15	Administrative and General	0	0	0	0	(14,295)
16	Total Operation & Maintenance	($1,070)	($2,355)	($1,946)	$0	($18,066)
17	Depreciation					($8,790)
18	Amortization	0	0	0	0	(676)
19	Taxes Other than Income	0	0	0	0	0
20	Income Taxes	407	1,094	740	40	11,256
21	Miscellaneous Revenue and Expense					0
22	Total Operating Expenses	($663)	($1,261)	($1,206)	$40	($16,276)
23	Net Operating Revenues	$663	$1,783	$1,208	($40)	$20,050
24	Average Rate Base					
25	Electric Plant in Service	$0	$0	$0	$0	($706)
26	Accumulated Depreciation & Amortization	0	0	0	0	(555)
27	Accumulated Deferred Income Taxes					(974)
28	Accumulated Deferred Inv. Tax Credit					0
29	Net Utility Plant	$0	$0	$0	$0	($2,235)
30	Plant Held for Future Use					0
31	Acquisition Adjustments					0
32	Working Capital	(14)	(26)	(25)	1	(338)
33	Fuel Stock					0
34	Materials & Supplies					0
35	Customer Adv for Const					0
36	Weatherization Loans					0
37	Prepayments					0
38	Misc. Deferred Debits					0
39	Misc. Rate Base Additions/(Deductions)				(3,403)	(2,839)
40	Total Average Rate Base	($14)	($26)	($26)	($3,402)	($6,412)
41	Revenue Requirement Effect	($1,099)	($2,955)	($2,000)	($400)	($33,930)