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

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 Additioual 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.
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> 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 PORTLAND GENERAL ELECTRIC COMPANY - Advice No. 93-26	)))))	STIPULATION

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

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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 Center

(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

P.O.G.

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	0.00200
	Total	0.00555

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

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) SUPPLEMENT #1
COMPANY - Advice No. 93-26)

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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

Stipulation Supplement 1
Attachment 1
Page 1 of 9

TO: Janice Fulker
Oregon Public Utility Commission

May 22, 1990

FROM: Warren Winter, PGE
Manager - Economic Regulation

RECEIVED
MAY 1990
OPUC
SALEM

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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SALEM

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 P. McCullough
James H. Baggenstos

January 10, 1983

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

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.

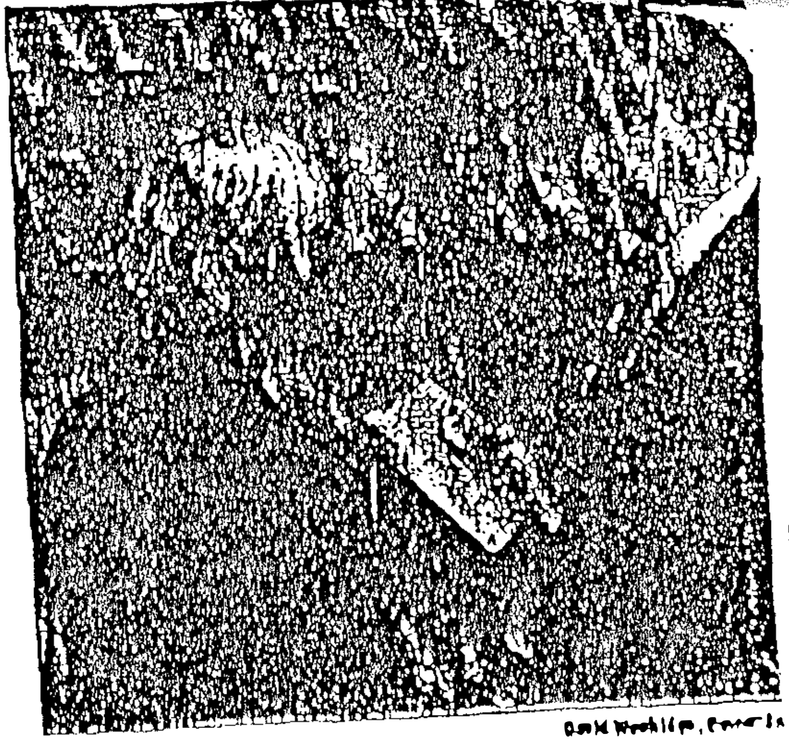
The Company also intends to issue $80 million of pollution control bonds in April 1984 at 10.25 percent for the purpose of refunding the 8.75 percent issue that is due June 1, 1984. No drawdown from this fund is expected during the test period.

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

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



[illegible]

INTERRUPT

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 and talk to our energy experts. We'll g the facts, without the fine print.

POW
SMA
1 800 567

Electric Heat... the smart choice.

SPRING 93

Expedition Supplement 1
Attachment 2
Page 1 of 1

95-322

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 8[illegible] 567 8700

COPY

95-322

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

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[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

95-322

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;

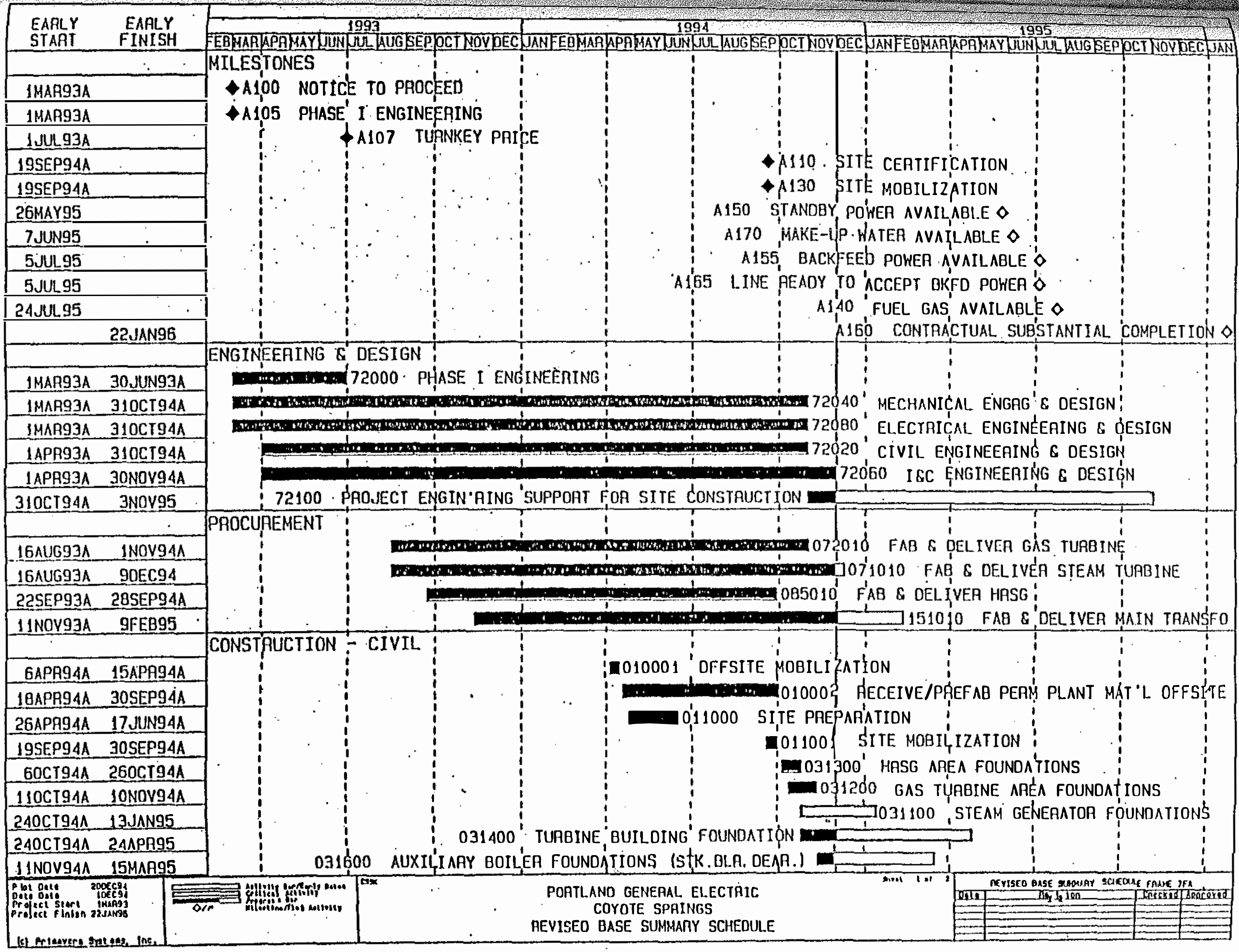
B. Notice to Proceed With Construction was not issued on or prior to March 1, 1994 as provided in Section 4 of the EPC Contract but instead was issued September 19, 1994;

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

Amended Exhibit C

KEY DATES



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 ENGRG & 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.)

Plot Date 20DEC94
Data Date 10DEC94
Project Start 1MAR93
Project Finish 22JAN96

(c) Primavera Systems, Inc.

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

CSSK

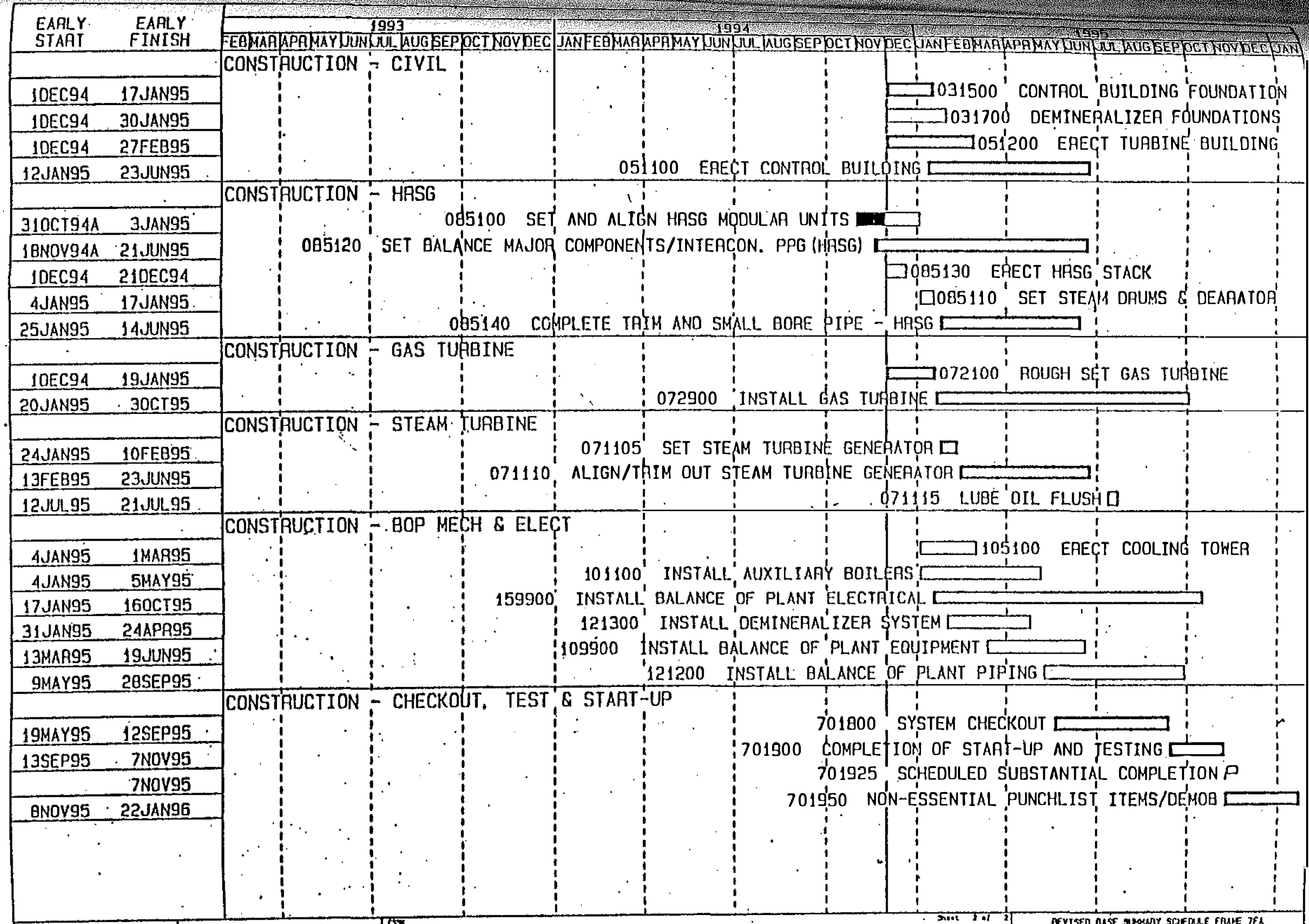
Sheet 1 of 2

PORTLAND GENERAL ELECTRIC
COYOTE SPRINGS
REVISED BASE SUMMARY SCHEDULE

REVISED BASE SUMMARY SCHEDULE FRAME 7FA

Date	Revision	Checked	Approved

C-1



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	085130 ERECT HRSG STACK
4JAN95	17JAN95	085110 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	3OCT95	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

REVISED BASE SUMMARY SCHEDULE FRAME 7FA

Date	Revision	Checked	Approved

KEY DATES

(i)

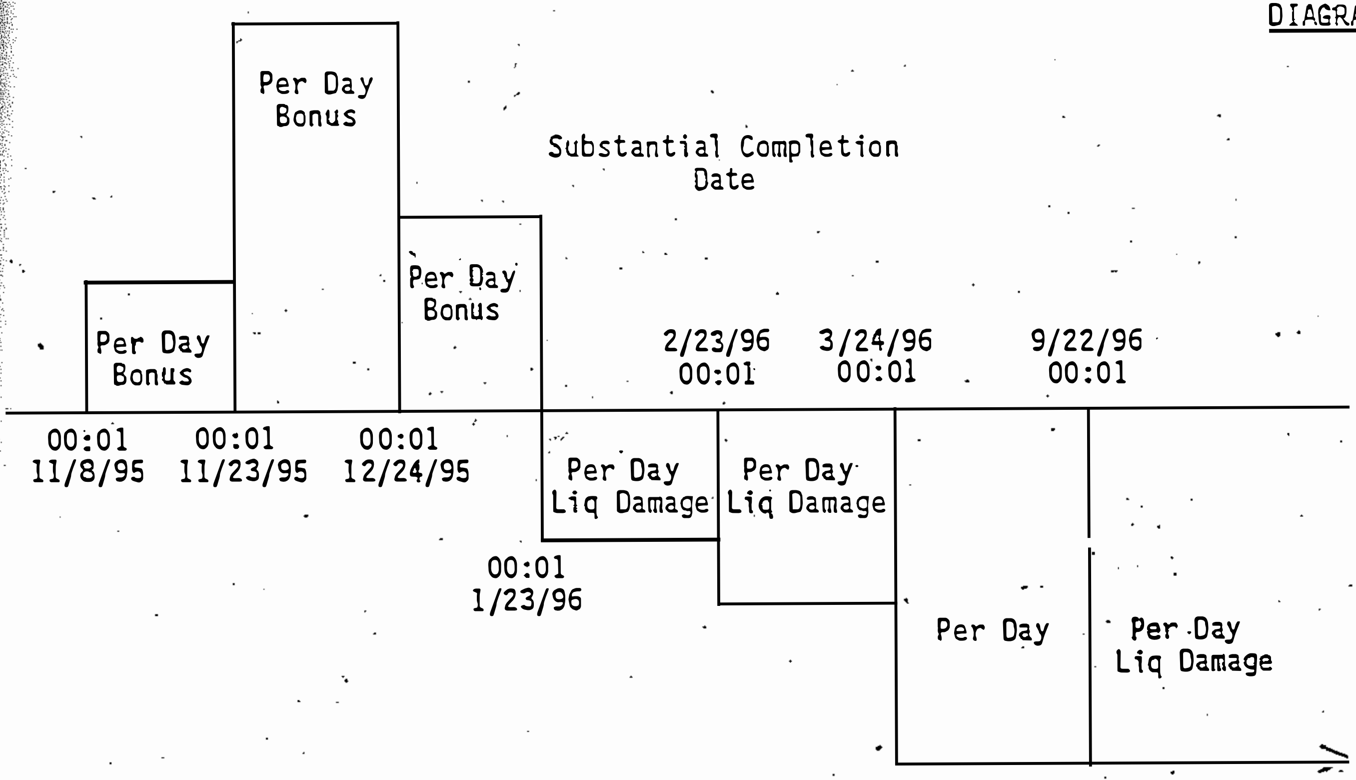
(ii)

(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 PORTLAND GENERAL ELECTRIC COMPANY - Advice No. 93-26	)))))	**STIPULATION**

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)

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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						
		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)

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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)

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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)

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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)

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		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)

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		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

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PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
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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**

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		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

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	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

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	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

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	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

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	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

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	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

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	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	($481)

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

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PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1996
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		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	**Rate of Return**	5.84%		7.63%		9.60%
33	**Implied Return on Equity**	3.08%		7.36%		11.60%

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		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)

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Portland General Electric Co.
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		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)

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Portland General Electric Co.
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		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)

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		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)

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		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)

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Adjustments to Oregon Results
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		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)

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		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)

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UE-88 Test Year Based on 1996
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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

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Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
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	Income Tax Calculations	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)
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

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Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
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		Miscellaneous Corrections to Company Filing						
	Income Tax Calculations	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

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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

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

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

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

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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

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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

PORTLAND GENERAL ELECTRIC COMPANY
RATE DESIGN SUMMARY TABLE
25-Mar-95 MONTHLY REVENUE MODEL

FORECAST STFPUC94
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%

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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%

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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

				REVENUES		INCREASE IN REVENUES	
				AFTER RPA	AFTER RPA		
CUSTOMER CLASSIFICATION	RATE SCHEDULE	AVERAGE CUSTOMERS	KWH SALES (000'S)	E-15 PH I With Adjustments	E-16 PH I With Adjustments	AMOUNT	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							
OEMAND 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%

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

		Marginal Costs		Present Revenue				Proposed Revenue			
	Loads (a)	($000) (b)	mills/kWh (c)	($000) (d)	mills/kWh (e)	% of Marg Cost (f)=(e)/(c)	Indexed(1) % of Marg Cost (g)	($000) (h)	mills/kWh (i)	% of Marg Cost (j)=(i)/(c)	Indexed(1) % of 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.

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