ORDER NO. 01-787

ENTERED SEP 07 2001

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 116

In the Matter of PacifiCorp's Proposal to	)	
Restructure and Reprice its Services in	)	ORDER
Accordance with the Provisions of SB 1149.	)	

SUMMARY

In this order, the Commission approves new rate schedules for PacifiCorp. The overall increase, net of the benefits of low-cost subscription power from the Bonneville Power Administration (BPA), is just over one percent. Residential customers may see a slight decrease, while commercial and industrial customers face about a two percent increase. The specific rate changes will be determined on September 10, 2001, when the company submits a filing complying with the terms of this order. The new rate schedules and the associated tariff rules also establish the framework for PacifiCorp to offer power supply options to customers on March 1, 2002, under the terms of Senate Bill 1149, an electric industry restructuring bill.[1]

In addition, the Commission approves a provision that allows for a rate adjustment January 1, 2002 reflecting the power costs actually incurred by PacifiCorp. Further, PacifiCorp will submit a new power cost filing later this year based on a new power cost model.

The Commission also adopts a tiered rate structure for residential customers that will benefit customers who use lower amounts of energy. The first 500 kWh of electricity used is priced lower than electricity used above and beyond that amount. In addition, the rate design also ensures that residential and small farm customers receive the full benefit of BPA subscription power.

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[1] SB 1149 was passed by the 1999 Legislative Assembly, and codified, in part, at ORS 757.600 *et seq*. House Bill 3633, passed by the 2001 Legislative Assembly, delays the implementation of SB 1149 from October 1, 2001 to March 1, 2002.

INTRODUCTION

Procedural Background

On October 2, 2000, PacifiCorp filed Advice No. 00-014 which contained comprehensive tariff rules and supporting testimony covering direct access, portfolio access, standard offer, ongoing valuation, default supply, labeling, ancillary services, metering, electricity service supplier (ESS) certification, scheduling and balancing, ESS consumer protection, and coordination of supplier changes and billing. The effective date of this filing is October 1, 2001.[2]

On November 1, 2000, PacifiCorp filed Advice No. 00-015, an application for a general rate increase of $160.6 million, or 20.4 percent, in Oregon revenues. The filing also included PacifiCorp's proposals for complying with the provisions of Commission administrative rules regarding SB 1149. PacifiCorp requested that the rates take effect December 1, 2000.

On November 21, 2000, the Commission found good and sufficient cause to investigate the propriety and reasonableness of the tariff sheets pursuant to ORS 757.210 and 757.215. The Commission ordered the rates to be suspended for six months from December 1, 2000. The Commission further determined that as its investigation could not be completed within the initial six-month suspension period, an additional three-month suspension period should be added, making a total suspension period of nine months.[3] The initial suspension period expired on August 31, 2001. The suspension period was later extended through September 7, 2001.[4]

On June 1, 2001, PacifiCorp filed Advice No. 01-015 regarding portfolio options. This filing replaced the placeholder tariff sheet previously filed in Advice No. 00-015. Additional changes were made and filed by PacifiCorp in July 2001. For purposes of this order, we treat the placeholder tariff sheet filed in November 2000 as if it were withdrawn. Portfolio option tariff issues are not discussed in this order. We understand that Staff and PacifiCorp have agreed to take this issue to a Commission regular public meeting in the near future. All issues regarding portfolio option tariffs will be resolved in a future order.

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[2] This docket actually opened with a motion. On September 14, 2000, PacifiCorp filed a Motion for Extension of Time, asking for additional time in which to make its filings pursuant to administrative rules implementing SB 1149. Specifically, PacifiCorp asked to submit a portion of its filing by the required October 1, 2000 date, with the remainder of its tariff filing to be submitted by November 1, 2000. On September 29, 2000, the Commission granted PacifiCorp's request. *See* Order No. 00-600.

[3] *See* Order No. 00-758, issued November 29, 2000.

[4] *See* Order No. 01-749, issued August 23, 2001.

Conferences

On October 24, 2000, a prehearing conference was held in Salem, Oregon, to identify parties and interested persons and to adopt a procedural schedule. Additional prehearing conferences were held on December 12, 2000, and March 8 and May 18, 2001. A status conference was held August 20, 2001. The following participated as parties in this proceeding: PG&E National Energy Group; Renewable Northwest Project; NW Natural; Citizens' Utility Board (CUB); Northwest Energy Coalition; Portland General Electric Company (PGE); Industrial Customers of Northwest Utilities (ICNU); Oregon Department of Energy, Associated Oregon Industries; City of Portland; Portland BOMA; League of Oregon Cities; Enron Energy Services, Inc.; OreMet-Wah Chang; J. Tim Watson; City of Hermiston; City of Klamath Falls; and Fred Meyer Stores.

Public Comment Meetings

The general public was given an opportunity to comment on PacifiCorp's filings at several meetings scheduled around the State of Oregon. These meetings were held in Portland on January 8, 2001; in Bend on January 23, 2001; and in Medford on January 26, 2001.

Presentations to the Commission

On March 22 and May 8, 2001, special public meetings were held before the Commission, during which PacifiCorp and other parties had an opportunity to present information and obtain guidance from the Commission regarding policy matters under SB 1149. PacifiCorp, PGE, ICNU, CUB, City of Portland (City), League of Oregon Cities (League), Fred Meyer Stores, and Staff participated in one or both of these meetings.

On July 5, 2001, PacifiCorp, ICNU, Oregon Department of Energy, CUB, and Staff presented final closing arguments to the Commission.

Evidentiary Hearings

Hearings were held in Salem, Oregon, before Administrative Law Judge Kathryn Logan on May 29, 30, 31, and June 7, 2001. During those proceedings, the following appearances were entered:

> Katherine McDowell, James Van Nostrand, Jennifer Horan, Marcus Wood, and George Galloway, attorneys, represented PacifiCorp.
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> Melinda Davison, Brad Van Cleve, and Irion Sanger, attorneys, represented ICNU.

Terrence Thatcher, attorney, represented City of Portland.

Jason Eisdorfer, attorney, represented CUB.

Stephanie Andrus, Assistant Attorney General, represented Staff.

Commission Orders

The Commission issued three orders discussing procedural issues which needed resolution during this proceeding. On March 9, 2001, the Commission issued Order No. 01-219, granting PacifiCorp additional protection for confidential information.

On March 21, 2001, the Commission issued Order No. 01-249, addressing ICNU's request to allow a former Commission employee to participate as ICNU's expert witness. In explaining OAR 860-012-0010(2), the rule regarding appearances by former employees, the Commission outlined its process for determining whether a former employee could testify for another party. Using its analysis, the Commission determined that the former employee could not be a witness in this docket or in UE 115, the PGE restructuring and rate case, due to his involvement with both cases as a Commission employee.

On July 20, 2001, the Commission issued Order No. 01-592, which involved a question certified to the Commission by the presiding Administrative Law Judges in UE 115 and UE 116. PacifiCorp and PGE questioned whether the Internal Operating Guidelines adopted by the Commission in March 2001[5] provided necessary legal safeguards. PacifiCorp and PGE also asked the Commission to adopt recommendations made by the legislative task force regarding "Party Staff." The Commission determined that the Internal Operating Guidelines and Staff's procedures were legal. The Commission further determined that, while the task force recommendations would not be fully implemented in either UE 115 or UE 116, Staff witnesses who sponsored testimony or testified at hearing would not be present at a decision meeting. Finally, the Commission decided that only "nonparty" Staff members would attend the decision meetings regarding return on equity and rate of return.

Stipulations

On March 13, 2001, PacifiCorp and Staff filed a stipulation partially resolving revenue requirement issues. This stipulation, supported by the joint testimony of Judy Johnson (Staff) and Bruce Hellebuyck (PacifiCorp), reduced PacifiCorp's revenue requirement by approximately $19.5 million. The stipulation is attached to this order as Appendix A.

[5] *See* Order No. 01-253, issued March 26, 2001.

On May 29, 2001, City of Portland, League of Oregon Cities, and PacifiCorp submitted a stipulation regarding various issues. This stipulation is attached to this order as Appendix B.

On July 5, 2001, Staff, ICNU, and PacifiCorp submitted a stipulation regarding the standard offer and transmission credit. This stipulation, which is supported by the joint testimony of Bryan Conway (Staff), Lincoln Wolverton (ICNU), and Gregory Duvall (PacifiCorp), is attached as Appendix C.

On August 23, 2001, Staff, ICNU, CUB, and PacifiCorp submitted a stipulation and joint testimony resolving many of the power cost issues. This stipulation is attached as Appendix D.

The stipulations and supporting testimony were entered into the record as evidence pursuant to OAR 860-014-0085(1).

Based on the record in these proceedings, the Commission makes the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Applicable Law

In a rate case, the Commission's function involves two primary steps. First, we must determine the amount of revenue an entity, such as PacifiCorp, is entitled to receive. The utility's revenue requirement is determined on the basis of the utility's costs.[6] Second, we must allocate the revenue requirement among the utility's customer classes and design rates within classes.

In the revenue requirement phase of a rate case, the Commission must determine for a specified test year: (1) the gross utility revenues; (2) the utility's reasonable operating expenses to provide utility service; (3) the rate base on which a return should be earned; and (4) the rate of return to be applied to the rate base to establish the return to which utility stockholders are reasonably entitled.[7] Once these components are known, the Commission is then able to set utility rates that are at just and reasonable levels.

Burden of Proof

PacifiCorp raises an issue as to the application of the burden of proof in this case. PacifiCorp, citing *In re U S WEST Communication, Inc.*, UT 125, Order No. 97-171 (1997) as the Commission's "most recent pronouncement" on burden of proof

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[6] *See, e.g., American Can Co. v. Lobdell,* 55 Or App 451, 454-55, *rev den* 293 Or 190 (1982).
[7] *See Pacific Northwest Bell Tel. Co. v. Sabin,* 21 Or App 200, 205 n.4, *rev den* (1975).

in rate cases, claims that as the burden of going forward shifts, the burden of persuasion also shifts.[8] According to PacifiCorp, if a party presents evidence in opposition to a cost proposed by PacifiCorp, then that opposing party has the burden to persuade the Commission that PacifiCorp's costs are not reasonable. If the opposing party is unable to meet its burden, then the cost initially proposed by PacifiCorp must be adopted.

We believe this analysis creates an incorrect application of the law. Under ORS 757.210, a "utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable." This burden is borne by the utility throughout the proceeding and does not shift to any other party.

If, as in this case, PacifiCorp makes a proposed change which is disputed by another party, PacifiCorp still has the burden to show, by a preponderance of evidence, that its suggested change is just and reasonable. If it fails to meet that burden, either because the opposing party presented compelling evidence in opposition to the proposal, or because PacifiCorp initially failed to present compelling information, then PacifiCorp does not prevail.

Much is made of some language in Order No. 97-171, issued May 19, 1997. In that case, U S WEST argued that Staff had the burden of proof when it proposed to disallow expenses or to make adjustments to the test year. The language quoted by PacifiCorp indicates that the Commission approved of a shifting burden of persuasion.[9] However, the Commission stated in the concluding paragraph of the section:

> The Commission's role is to weigh the evidence presented on each issue in the case and determine where the preponderance lies. We make that decision on the record as a whole. The basic decision we make with respect to each issue in this case is whether the utility has produced persuasive evidence that its revenue requirement is reasonable. A component of that decision is whether Staff has persuasively rebutted [U S WEST's] revenue requirement evidence. We reject [U S WEST's] arguments that

[8] *See* PacifiCorp's Opening Brief, pp. 5-6.
[9] The language that PacifiCorp wants to have applied is as follows:

> [U S WEST] as the proponent of the rate increase must submit evidence showing that its proposed rates are just and reasonable. Once [U S WEST] has presented its evidence, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Staff or an intervenor, if it opposes the utility's claimed costs, must in turn show that the costs are not reasonable. *Each time the burden of going forward shifts, the burden of persuasion shifts as well. That is, each party who has the burden of going forward must, in order to prevail, persuade us by competent evidence that its position with respect to that set of costs should prevail. Id.* at 8 (emphasis added).

> Staff has the "burden of proof" with respect to disallowances and test year adjustments, because the arguments distort the way evidence is presented and decisions are made in a rate case.
> *Id.* at 8.

When the section is read in its entirety, it is clear that the Commission did not agree with U S WEST's arguments about shifting burdens.

PacifiCorp correctly points out that the Commission rescinded Order No. 97-171[10], but readopted portions of it in Order No. 00-191. The language relied upon by PacifiCorp was not readopted in Order No. 00-191. However, a general reference to the rescinded section was placed in the new order.[11] PacifiCorp contends that since this reference was made in the readopted section, the Commission must have wanted to adopt the entire discussion regarding burden of proof contained in the original order. Rather than imputing adoption by reference, as PacifiCorp attempts to do, it is clear that we simply made an error by placing a reference in Order No. 00-191 to a section that does not exist.

We do not grant PacifiCorp’s request to readopt the language found in the rescinded UT 125 order. That language, taken out of context, is an incorrect statement of the law under ORS 757.210. Rather, we choose to adhere to the language stated in UG 132:

> As the petitioner in this rate case, Northwest Natural has the burden of proof on all issues.[statutory language and citation omitted] Thus, Northwest Natural must submit evidence showing that its proposed rates are just and reasonable. Once the company has presented its evidence, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Staff or an intervenor, if it opposes the utility's claim costs, may in turn show that the costs are not reasonable.[12]

[10] *See*, Order No. 00-190, issued April 14, 2000.

[11] Specifically, Order No. 00-191 at 15 states:

> As we stated above, in the section called [U S WEST's] Burden of Proof Argument, [U S WEST] must show that its expenses are reasonable for us to allow them as part of the revenue requirement calculation.

However, Order No. 00-191 does not contain a section entitled "[U S WEST's] Burden of Proof Argument."

[12] Order No. 99-697, issued November 12, 1999.

Deferral to Staff's Case

PacifiCorp also argues that we should not "defer" to Staff's case for two reasons: (1) Staff never considered the overall result of its recommendations, and (2) Staff did not follow the Commission's Internal Operating Guidelines.

Prior to discussing the specific issues raised by PacifiCorp, we wish to address PacifiCorp's understanding of how we review the evidence. We do not "defer" to any party's presentation, but rather review the evidence presented and make findings of fact and conclusions of law based upon that evidence. Our responsibility is to make certain that the result reached is just and reasonable.[13]

Staff claimed that if all of its adjustments are reasonable, then the sum of the adjustments must be reasonable. While there is a certain logic to Staff's position, Staff should review the overall results of its adjustments. This review would assist Staff, and ultimately the Commission, in deciding whether the sum of its adjustments are, in fact, reasonable.

The remaining issue involves PacifiCorp's concern over Staff's compliance with the Internal Operating Guidelines.[14] A review of PacifiCorp's contentions regarding Staff noncompliance,[15] however, supports the concept that PacifiCorp simply disagreed with Staff's analysis. Without going into great detail, the issues raised by PacifiCorp involve how a question is framed and the type of information Staff believes is relevant for a Commission decision. While PacifiCorp claims that these "procedural deficiencies affect the substance of the Staff case and are prejudicial to PacifiCorp,"[16] in fact, all parties, including Staff and PacifiCorp, provided sufficient evidence upon which this Commission may make a reasonable determination.

Finally, we specifically reject PacifiCorp's implication that a Staff position is legally suspect because it is not accompanied by a list of alternatives and a preferred outcome. That was not the intent of our Internal Operating Guidelines. We adopted these guidelines for the purpose of obtaining, not excluding, information. We will not reject a persuasive analysis, supported by convincing evidence, merely because it does not come with alternatives. Such a wooden approach to decision-making does not serve anyone's interest.

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[13] PacifiCorp appears to believe that we do not consider the overall result of recommendations made to us. This confusion may have occurred due to the manner in which our decisions are communicated to the parties. In a contested case order, such as this one, we articulate our determinations on an issue-by-issue basis so that someone reading our order can identify the areas of dispute and can ascertain the Commission's analysis and resolution of those disputes.

[14] *See* Order No. 01-253, issued March 26, 2001.

[15] PacifiCorp claimed that Staff did not: (1) analyze the facts to recognize the impacts of particular outcomes on PacifiCorp, (2) appreciate the advantages to customers of PacifiCorp being able to conduct its operations as a financially sound enterprise, (3) provide several possible outcomes on issues of significant controversy, and (4) act objectively, but rather advocated against the interests of PacifiCorp.

[16] PacifiCorp Opening Brief at 16.

STIPULATED ISSUES

PacifiCorp entered into four stipulations to resolve various issues raised by parties. We address each separately.

I. Revenue Requirement Stipulation

On March 13, 2001, PacifiCorp and Staff filed a stipulation regarding numerous revenue requirement issues. PacifiCorp's initial filing sought a $160.6 million revenue requirement increase. The stipulation reduces this amount by approximately $19.5 million.

This stipulation is intended to resolve numerous revenue requirement adjustments proposed by Staff. [17] PacifiCorp and Staff believe that these adjustments are supported by the evidence and are reasonable for purposes of this proceeding. While CUB and ICNU do not oppose these adjustments, they believe that some of the adjustments should be greater than the amounts determined by Staff and PacifiCorp. As we understand ICNU's and CUB's arguments, these stipulated amounts are minimum base adjustments to be made. We will respond to CUB's and ICNU's contentions regarding additional adjustments during our discussion of contested issues.

Having reviewed the March 13th Stipulation, we find the proposed adjustments contained therein to be reasonable. The Stipulation set forth in Appendix A is adopted.

II. City and League Stipulation

On May 29, 2001, the City of Portland (City), the League of Oregon Cities (League), and PacifiCorp submitted a stipulation to resolve specific issues raised by both the City and League in their opening testimony.

The parties reached resolution on three topics: portfolio ballot processing fees, reclassification of small nonresidential consumers, and standard service agreements with electric suppliers. The City and League further agreed that, except for the matters listed below, all other issues addressed in their testimony will not be pursued in this docket but may be addressed in other proceedings:

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[17] We note that the list of Stipulated Adjustments includes four subjects: Schedule 290, Public Purpose Charge; Rule 21, Direct Access; Tariff Schedule Review; and Proposed Revisions to Various Rules and Schedules, for which no revenue requirement effect for 2001 is noted. Further, these four subjects are not discussed in the testimony in support of the stipulation. As they have no revenue requirement effect, and the testimony does not list these subjects as part of the stipulation, we are not considering these four subjects to be part of the stipulation.

1. Schedule 53 – Remove restriction upon availability of service under this tariff within allocated service territory in Multnomah County;

2. Schedule 71 - Reduce minimum size of eligible customer from 1 MW to 250 kW and permit aggregation of accounts if the consumer is willing to bear incremental metering costs;
3. Schedule 135 – Update avoided costs data and incorporate avoided transmission costs into payments by PacifiCorp; and

4. Rule 8 – Permit aggregation of accounts through net metering.

The parties agreed that residential and small nonresidential customers could make a first initial selection, and an annual change thereafter, among the portfolio options without paying a processing fee. The costs incurred by PacifiCorp to process the initial portfolio ballot and the annual change are to be treated as implementation costs that PacifiCorp may recover from all "consumers eligible to participate in the Portfolio Options, as authorized by OAR 860-038-0220(9)."[18] However, PacifiCorp would charge a $5 processing fee for customers who change options more than once annually. Finally, the parties specifically conditioned their agreement on their belief that OAR 860-038-0220(9) authorizes these costs to be recovered from all consumers eligible to participate in the portfolio options. If this belief is incorrect, then the parties no longer have an agreement on portfolio ballot processing fees.

We have reserved discussion of several SB 1149 issues for a supplemental order to be issued at a later date. We defer discussion of portfolio ballot processing fees and standard service agreements to that supplemental order.

As for the automatic reclassification issue, our understanding of the stipulation is that the League and City agree that a nonresidential consumer can automatically change classifications between "large" and "small" depending on the nonresidential consumer's usage. This is consistent with our rules.

We adopt this stipulation, attached as Appendix B, except for the portions that discuss portfolio ballot processing fees and standard service agreements.

[18] *See* paragraph 9, page 2 of Stipulation.

III. Standard Offer and Transition Credit Stipulation

On July 6, 2001, Staff, ICNU, and PacifiCorp submitted a stipulation with supporting testimony regarding the standard offer and transition credit (adjustment). PacifiCorp proposes to offer to all non-residential consumers, during a two day period,[19] a choice of a traditional cost of service rate, a daily standard offer rate, or direct access service from a third party supplier. Through the use of a "buyback calculator," a consumer may return to the traditional cost of service schedule after having gone to direct access or standard offer. This "buyback calculator" requires a returning consumer to pay for the direct incremental costs associated with change. Finally, a transition adjustment is adopted, which allows prices to be adjusted to reflect the results of the ongoing valuation method under OAR 860-038-0140. A balancing account will be established, with interest accruing at the authorized rate of return.

We have reviewed the July 6th Stipulation and find it to be reasonable and in the public interest. The stipulation set forth in Appendix C and attached to this Order is adopted.

IV. Power Cost Stipulation

On August 23, 2001, Staff, ICNU, CUB, and PacifiCorp filed a stipulation intended to resolve power cost issues. At the outset, the parties note that PacifiCorp is currently developing a new power cost model to replace its existing PD-Mac model. PacifiCorp has agreed to work with interested parties in developing the new model and to submit a new power cost filing by the end of November 2001. The stipulating parties agree to support a procedural schedule in that future docket that would result in a Commission decision determining new net power costs and new rates by May 31, 2002.

The stipulation resolves all power costs issues listed in Attachment 1 to the stipulation. These include issues raised in prefiled testimony by Staff, ICNU and CUB relating to the PD-Mac model, the expiration of special sales contracts, coal costs, and those related to prudence. If there is no Commission decision on PacifiCorp's new power cost filing by May 31, 2002, the parties agree that the stipulation will continue, except for the limitation on prudence challenges.

The body of the power cost stipulation is intended to handle power cost issues from the order date in this docket until May 31, 2002 (the "Bridge Period.") For the Bridge Period, the parties agree that PacifiCorp's power cost recovery will be based on a stipulated percentage of the company's actual—not normalized—power costs

[19] The testimony in support of the stipulation states, at page 2, line 18: "The Company proposes that during the two-day period of September 5-7, (or a comparable date, if direct access is delayed)[.] " While the parties have called it a two-day period, the dates establish a three-day period. We assume, and so find, that the parties actually meant a 48-hour period which incorporates part of these three days.

adjusted according to the terms of the stipulation. Specifically, PacifiCorp's allowed power cost recovery will be calculated as follows:

Power Cost Recovery = [(Adjusted Actual Total Company Power Costs x 83%) – (Change in Special Contract Revenues x 92.9%)] x (Jurisdictional Allocation) + (Auditing Costs)

For the purpose of setting rates in this docket, the parties agree that the initial baseline annual power costs should be set at $595 million on a total company basis. This figure represents a compromise number for purposes of the stipulation and was selected with the goal that PacifiCorp would not under- or over-collect power costs during the Bridge Period. The initial baseline will be reviewed after three months of operation pursuant to a company filing by December 1, 2001. If it is determined that the initial baseline will result in an overcollection or undercollection of over $60 million on a total company basis during the Bridge Period, a reset baseline and rate adjustment will be established effective January 1, 2002.

The stipulation also contains a mechanism for auditing actual power costs at the end of the Bridge Period. This audit will review monthly actual and adjusted actual total company power costs for accounting treatment, costs, loads, and identification of irregularities relating to PacifiCorp power purchases and plant operations. The parties agree that an independent auditor will audit PacifiCorp's power costs, with the auditing costs to be included in the allowed power cost recovery.

This stipulation represents a compromise of the positions of the active parties to this docket concerning power costs. The stipulation is based on the evidentiary record in this case. The initial baseline agreed to in the stipulation is within the range of power costs positions made by the parties in opening and reply briefs filed with the Commission. No party opposes the stipulation.

As the executing parties note, the stipulation establishes a process for the development and review of a new power cost model for PacifiCorp. By November 30, 2001, PacifiCorp will file an application that presents the new power cost model and seek approval of the resulting net power costs. The parties agree to support a schedule that will result in a Commission decision by May 31, 2002 in that docket.

For the interim period, the stipulation establishes a rate mechanism that sets the company's power costs at a reasonable level. The initial baseline is used to set rates, and differences between the initial baseline net power costs and a stipulated percentage of adjusted actual company power costs will be deferred for later amortization pursuant to ORS 757.259. The stipulation requires a review of the initial baseline in December 2001 and, if that amount is expected to significantly depart from the stipulated percentage of adjusted actual power costs, the baseline amount will be adjusted for the remaining period. The stipulation also requires an accounting audit of PacifiCorp's power costs.

After a review of the stipulation, supporting testimony, and the evidentiary record in this docket, we conclude that the stipulated power cost recovery mechanism provides a reasonable level of power cost recovery for PacifiCorp. Accordingly, the power cost stipulation, attached as Appendix D, is adopted.

CONTESTED ISSUES

The issues will be addressed in four broad categories for purposes of discussion: 1) Rate of Return; 2) Power Costs, and 3) Traditional Issues other than Rate of Return; and 4) SB 1149 Issues.

I. Rate of Return

In 1944, the United States Supreme Court established the standard for determining cost of capital allowance in utility ratemaking proceedings:

> [T]he return to equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital[.][20]

To determine an appropriate rate of return on rate base for PacifiCorp, the costs and components of the company's capital structure first must be identified. Each capital component cost is estimated and weighted according to its percentage of total capitalization. These weighted costs of capital are then combined to calculate PacifiCorp's overall cost of capital, which becomes the allowed rate of return on rate base.

A. Capital Structure

Initially, Staff and PacifiCorp did not agree on the capital structure to be used in this case. However, in its opening brief filed June 25, 2001, PacifiCorp asked that its actual capitalization be used rather than its previously recommended consolidated utility capitalization. Staff agreed to the use of PacifiCorp's actual capital structure as of March 30, 2001, which is consistent with prior Commission precedent.[21] Therefore, we adopt PacifiCorp's capital structure figures as of March 31, 2001. These are:

Long-Term Debt	45.0 percent
Preferred Stock	8.7 percent
Common Equity	46.3 percent

[20] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944). The Oregon legislature recently adopted this standard in HB 3502, which amends ORS 756.040(1).
[21] *In Re Northwest Natural Gas Company*, Order No. 99-697, issued November 12, 1999.

B. **Cost of Long-term Debt**

PacifiCorp calculated the amount of debt on those series which were outstanding as of September 30, 2000. Then the outstanding balances were reduced by $98.1 million for maturities, principal amortization and sinking fund requirements due to occur between October 1, 2000 through June 30, 2001. PacifiCorp selected June 30, 2001 as the date for determining cost of debt as it is the mid-point of the 2001 test year.[22] PacifiCorp used the same methodology for calculating embedded costs of debt that it has used in its previous Oregon rate cases. Based upon its calculations, PacifiCorp's estimate of embedded cost of long-term debt as of June 30, 2001 is 6.926 percent.

Staff accepted the methodology used by PacifiCorp, but made modifications by excluding certain expenses that were non-recurring or not tied to a specific debt series. Staff also excluded some long-term debt because it is actually short-term debt, i.e., it will mature within a year from when the rates go into effect. However, Staff assumed that the level of long-term debt would remain unchanged, so it calculated a new long-term debt cost rate using an interest rate forecast. Finally, Staff chose October 1, 2001, rather than June 30, 2001 as the date for determining cost of debt. Based on its calculations, Staff's estimate of PacifiCorp's embedded cost of long-term debt as of October 1, 2001, is 6.80 percent.

Before discussing the remaining issues, we find it necessary to clarify some terminology, and make clear the Commission's position on how debt is to be characterized.

The Commission has defined long-term debt as any debt with a maturity of more than one year. Concomitantly, the definition of short-term debt is a debt with a maturity of one year or less. PacifiCorp correctly points out that this definition is not located in any of our orders. Nevertheless, we have always used these definitions in our approval of stipulated rate cases, AFORs, and other cases where cost of debt has been resolved prior to hearing. In fact, we know of no rate case where the cost of long-term debt, or the definition of long-term debt, has been contested.

Further, it has been the Commission practice to remove short-term debt, as we define that term, from calculations of debt rates for rate cases. Again, this has not previously been stated in our orders as the parties have always resolved these matters. We are setting forth our practice in this order so that parties in the future will be clear as to how we define and use these terms.

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[22] A discussion of the test year is found on page 38 of this order.

1. Preferred Unsecured Debt Solicitation Costs

In May 1999, PacifiCorp solicited proxies from its preferred stock holders to consider a proposal to approve an increase of $5 billion in the amount of unsecured indebtedness. A special cash payment of up to $1.00 per share was made to each holder of record that voted for the proposal. Dealers who solicited votes in favor of the proposal were paid, as were co-solicitation agents who organized and executed the solicitation effort. Finally, additional expenses were incurred that were primarily advertising costs. The costs are itemized as follows:

Special Cash Payment to Shareholders	$2,143,000
Payments to Soliciting Dealers	696,000
Payments to Co-solicitation Agents	536,000
Miscellaneous expense (advertising)	65,000
Total	**$3,440,000**

PacifiCorp's purpose in gaining this approval was to increase its financial flexibility. According to PacifiCorp, having the flexibility to replace its secured debt with unsecured debt would give it the ability to obtain future funds on favorable terms. PacifiCorp is amortizing these costs on a straight-line basis over five years. The annual amortized expense is approximately $688,000.

Staff excluded these expenses in its calculation of long-term debt for three reasons: they are non-recurring; costs associated with issuing or redeeming debt should be included in the costs of each debt series; and PacifiCorp failed to establish that these costs were prudent or necessary. Specifically, PacifiCorp has not explained how the flexibility benefits customers, nor has PacifiCorp quantified this improved "financial flexibility." Staff is concerned that putting this type of special payment into base rates appears to be building a special dividend into rates.

While agreeing that the costs are non-recurring, PacifiCorp argues that this factor is irrelevant as to whether the costs are recoverable. PacifiCorp claims that the regulated customers are the direct beneficiaries of the financial flexibility it obtained from the shareholders. Currently PacifiCorp's debt securities are under review for possible downgrade by Moody's. If a downgrade occurs, then PacifiCorp's cost of debt will increase. PacifiCorp needs the flexibility in light of the current conditions. The cost cannot be associated with a particular series of debt, as it is unknown when PacifiCorp will issue new unsecured debt. Finally, the costs are prudent as this type of payment is consistent with industry practice.[23]

[23] In support of this claim, PacifiCorp submitted PPL 705, which was a summary of five electric companies outside of Oregon that engaged in similar actions (cash payments and solicitations).

We are not convinced that these costs should be considered as part of long-term debt. While PacifiCorp's intent of gaining flexibility may be prudent, PacifiCorp has not explained to our satisfaction the customer benefit of its increased financial flexibility. PacifiCorp has not quantified this benefit in any way, and currently does not have any plans to use its ability to issue new unsecured debt. The approximately $3.4 million in Preferred Unsecured Debt Solicitation Costs are excluded from the calculation of long-term debt.

2. Date for determining cost of long-term debt

PacifiCorp selected June 30, 2001[24] as the date for determining cost of debt, as it is the mid-point of the 2001 test year. Staff disagreed with this date, selecting October 1, 2001 as the date for determining the cost of long-term debt.

Staff is concerned about a large amount of PacifiCorp's high-cost debt that is due to mature between July and October 2002. According to Staff, including this large amount of high cost debt would skew PacifiCorp's embedded cost of long-term debt, resulting in a greater recovery over the period the rates are in place. Staff therefore selected October 1, 2001 as the date for determining the cost of debt because all debt maturing on or before October 1, 2002 would be considered short-term debt and excluded from this calculation.

The amount of debt that Staff wishes to exclude from long-term debt is:

August 2002	$52,000,000
September 2002	$76,000,000
Total	**$128,000,000**

PacifiCorp argues that the mid-term of the test year is the most logical point from which to determine long-term debt. However, this Commission has traditionally used the date that rates become effective as the triggering date for determining long-term debt. In other words, all debt that matures in one year or less from the effective date of rates is short-term debt which should be excluded from the long-term debt calculation, and debt that matures more than one year from the effective date of rates is long-term debt. Although we initially believed that new rates would be in effect by August, it now appears that the new rates will not actually go into effect until some time in mid-September. While this bolsters Staff's argument for using October 1, 2001, as the date for determining long-term debt, it is also the date that provides for "excluding" a significant amount of high cost debt. While there is basis for Staff's argument, it is inconsistent with our past practice. Rather than select a date mid-way through a month,

[24] The parties use two different dates, June 30 and July 1, as PacifiCorp' s date for determining the cost of debt. *Compare*, PPL/700 Williams/4, lines 5-8, and PPL/704 Williams/5, line 11 and Staff /1600 Conway 13, line 7. We need not resolve this ambiguity for purposes of our determination.

we will use September 1, 2001, as the date from which the cost of long-term debt will be calculated.

3. Cost of assumed new long-term debt

Staff assumed that debt which was excluded from the long-term debt calculation because it was short-term debt (in this case, debt maturing in one year or less from September 2001) would be replaced by new long-term debt with a seven-year maturity. The amount of assumed new long-term debt is $52,000,000. Staff then forecasted an interest rate for this assumed new long-term debt. Staff and PacifiCorp agree that as of May 10, 2001, a reasonable forecasted interest rate is 7.52 percent.

PacifiCorp disagreed with Staff's methodology, as it believes that cost of debt should be calculated from July 1, 2001. In addition, PacifiCorp raises further objections to Staff's assumption that replacement debt would mature in seven years. PacifiCorp contends that it is unlikely to issue all of its long-term debt with a seven-year maturity date, and that it is more realistic to use longer time periods, such as ten- and thirty-year maturity dates. Using estimates for April 5, 2001, PacifiCorp calculates ten and thirty-year fixed rate debt to be 7.44 percent and 8.31 percent, respectively.[25]

Staff agrees that it is likely that PacifiCorp will issue debt with varying dates of maturity, including debt with a maturity of greater than seven years. If PacifiCorp can demonstrate to Staff that the average maturity of new long-term debt has an average cost significantly different from the cost of seven-year debt, and that its mix of securities is in the interest of customers, Staff could support a different amount. However, Staff has not seen such information from PacifiCorp.

We are inclined to agree that PacifiCorp will issue long-term debt with a variety of maturity dates. While we understand Staff's rationale for selecting a seven-year maturity date, we think that PacifiCorp's position that its mix would result in a greater average maturity is reasonable. Using the latest data in this record, we find that the assumed new long-term debt should have a ten-year average maturity date, with a fixed rate of 7.89 percent.

Commission Resolution

We have removed the preferred unsecured debt solicitation costs from the cost of long-term debt. We have also decided that September 1, 2001 is the date from which the cost of long-term debt will be calculated. Finally, the cost of assumed new long-term debt, based on a ten-year average maturity date, is 7.89 percent. Using this revised data, we hold that the embedded cost of long-term debt should be 6.88 percent.

[25] The May 10, 2001, update for ten-year debt is 7.89 percent. PPL/706/Williams/4, line 10. PacifiCorp did not provide an update for thirty-year debt.

C. Cost of Preferred Stock

PacifiCorp used the same methodology for estimating the embedded costs of preferred stock as it did for estimating the costs of long-term debt, as discussed above. Its estimate of embedded cost of preferred stock is 6.182 percent.

Staff accepted PacifiCorp's methodology, but excluded $152,115 of costs associated with the issuance of QUIDS (Quarterly Income Debt Securities) as it is a non-recurring expense. Staff recommends that the Commission adopt 6.16 percent as the embedded cost of preferred stock.

Before turning to the parties' arguments, we provide the following background information. In 1995, two series of QUIDS (Quarterly Income Debt Securities) were issued. The first series contained $55,825,925 of 8.55 percent QUIDS, with a maturity date of December 31, 2025. These QUIDS were exchanged for $1.98 No Par Serial Preferred Stock, which resulted in an annual savings of $1.3 million in the cost of preferred stock. PacifiCorp incurred $2,520,556.25 of expenses in the exchange, which it is amortizing on a straight-line basis over the 30-year original life of the QUIDS. The annual amortization of the expense is $84,018.

The second series of QUIDS was issued to meet cash flow needs. PacifiCorp issued $120 million of 8 3/8 percent QUIDS with a maturity date of June 30, 2035. PacifiCorp believed issuing QUIDS was the most advantageous form of fixed rate financing available as the all-in after-tax costs of the QUIDS was nearly 225 basis points (or nearly $2.7 million annually) less than the cost of issuing comparable perpetual preferred stock. PacifiCorp incurred expenses of $4,323,604.12, which it is amortizing on a straight-line basis over the 40-year original life of the QUIDS. The annual amortization of the expense is $108,010 pre-tax, and $68,097 after tax (assuming a 37 percent tax rate). Both series of QUIDS were redeemed on November 20, 2000.

The issue presented is whether to allow the QUIDS expense of $152,115 (the sum of the two annual amortized rates, using the after-tax rate for the second series of QUIDS) to be considered as part of the cost of preferred stock.

PacifiCorp argues that including the expense is reasonable. The issuance of the QUIDS in 1995 was reasonable, and it benefited customers. Alternative securities either lacked the favorable equity treatment offered by rating agencies or were more expensive. Further, the costs associated with QUIDS have been part of the revenue requirement since they were issued. It is appropriate to amortize this expense in the manner selected by PacifiCorp, and but for the early redemption of the QUIDS, this issue would not exist. To exclude these expenses when the Company was acting prudently to reduce its debt is a form of a penalty and could discourage future retirement of securities.

PacifiCorp paid down higher long-term debt (the QUIDS) rather than pay down lower cost short-term debt at the time of redemption. PacifiCorp used cash proceeds it received from the sale of its Australian subsidiary to redeem the QUIDS. At the time of redemption, PacifiCorp estimated the annual benefit to the combined after-tax cost of debt and preferred stock at $2.2 million. According to PacifiCorp, the customers benefit from this cost reduction. However, if the Commission believes that recovery through preferred stock is not the appropriate avenue, PacifiCorp is agreeable to recovering these costs in some other manner, such as an operating expense.

Staff removed the expense, as the QUIDS were no longer outstanding, and the expense is non-recurring. According to Staff, PacifiCorp failed to establish any compelling reasons as to why the Commission should continue to recognize in rates any costs associated with these securities. While issuing QUIDS in 1995 might have been PacifiCorp's most reasonable option for financing, with customers receiving some benefit because higher cost financing was not chosen, this does not justify current recovery of costs.

A more appropriate way to view the transaction, according to Staff, is as an exchange of debt for equity. It is unclear to Staff if there are benefits due to the change in capital structure, because equity is more expensive than debt. While PacifiCorp showed that debt preferred costs fell, it failed to present any evidence that the overall cost of capital fell. If there was a benefit to customers by paying off the debt in November 2000, PacifiCorp has failed to show it.

Commission Resolution

In reviewing the record, we note that Staff consistently asked PacifiCorp to show the benefits the customers received when it redeemed the QUIDS in November 2000.[26] Although PacifiCorp did show that the cost of debt fell, this was paid for by an increase in equity. Equity is more expensive than debt. While customers may have benefited from the redemption of the QUIDS, PacifiCorp has not shown us any actual benefits to customers from its actions. Therefore, these costs should not be put into rates.

We understand PacifiCorp's contention that these expenses should be allowed. Under usual circumstances, the issuance costs would roll forward into the new debt instrument. In this case, no new debt was incurred. If the Commission had been given persuasive evidence as to how customers specifically benefited from PacifiCorp's decision to redeem the QUIDS, we would be inclined to allow the expense. However, the mere fact that the cost of debt costs fell does not establish that the overall cost of capital also fell. Further, as the expense is non-recurring, it is not appropriate for it to be recovered as some other type of expense.

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[26] Even through the time of hearing, Staff indicated that it would not be opposed to including the QUIDS expense if there was "some type of analysis that show that overall the cost of capital fell. . . " Staff Witness Bryan Conway; Tr. at 440, lines 23-25.

We do not want the parties to interpret this particular decision as an attempt to discourage companies from redeeming long-term debt, as PacifiCorp did in this instance. Our decision is based upon the proof that must be shown by a company to recover this type of expense when it cannot be recovered through a replacement security. We cannot "assume" that customers benefited by PacifiCorp's actions. Rather, PacifiCorp has the burden of persuasion to show us that these expenses should be allowed.

Based on our discussion above, we hold that the embedded cost of preferred stock should be 6.16 percent.

D. Cost of Equity

PacifiCorp seeks an authorized return on equity (ROE) of 11.5 percent.[27] PacifiCorp's ROE recommendations are based on the testimony of Samuel Hadaway, a Principal in FINANCO, Inc., Financial Analysis Consultants, and Thomas Zepp, Vice President of Utility Resources, Inc. Hadaway presented ROE estimates using a single-stage and multi-stage Discounted Cash Flow (DCF), a risk premium analysis and a comparison of authorized ROEs in other jurisdictions. Zepp presented ROE estimates using two versions (zero-beta and Sharpe-Lintner) of the Capital Asset Pricing Model (CAPM).[28]

Staff recommends a much lower ROE of 9.25 percent. Staff's ROE estimates are based on the testimony of Bryan Conway, Staff's Program Manager of Economic and Policy Analysis Section, and James A. Rothschild, President of Rothschild Financial Consulting. Conway presented ROE estimates using single-stage DCF, the Fisher-Kamin version of CAPM and a qualitative analysis of the Commission's most recent contested ROE decision in docket UG 132.[29] Rothschild presented ROE estimates using single- and multi-stage DCF and two versions of what he called the risk premium/CAPM method.[30]

Our discussion is divided by methodology. In each section, we review the methodology, summarize the parties' recommendations, and analyze and resolve the contested issues. We then conclude with a separate section in which we adopt an authorized ROE for PacifiCorp.

[27] This is the midpoint of its calculated range of 11.1 percent to 11.9 percent.
[28] PacifiCorp's final position, as reflected in the sursurrebuttal testimony, testimony at hearing, and concessions made during briefing, is what is reflected in this order. We do not discuss the various changes in positions that occurred over time.
[29] *In the Matter of the Application of Northwest Natural Gas Company for a General Rate Revision,* Order No. 99-697.
[30] As with PacifiCorp, this order reflects the final positions set forth by Staff. See fn 26.

1. Discounted Cash Flow (DCF)

The DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation. The return on equity under the DCF model is the rate that equates the current stock price and expected cash flows to investors.

In this case, the parties used two DCF models. The basic, or single-stage DCF formula, assumes a constant growth rate in future dividends. It is generally expressed as:

$$k_e = \frac{D_1}{P_0} + g$$

Where:

k_e = cost of equity
D_1 = dividends per share over the next 12 months;
P_0 = current stock price; and
g = annual growth rate in future dividends per share

The multi-stage, or complex DCF formula, assumes that growth rates may change over time. That formula is expressed as:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \ldots + \frac{D_n}{(1+k_e)^n}$$

Where:

$D_{1 \ldots} D_n$ = the expected stream of annual dividends per share.

DCF Estimates

Hadaway could not apply the DCF model directly to PacifiCorp because the utility is no longer publicly traded. Therefore, as a proxy for PacifiCorp, Hadaway selected a sample group of electric utilities.[31] The electric group consists of A- and higher rated electric utility companies that have at least 75 percent of total revenues from electric sales and for which complete and reliable data are available in *Value Line.*[32]

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[31] Hadaway also initially selected a proxy group of gas distribution companies. While we understand PacifiCorp's reason for including gas distribution companies, we do not agree that gas distribution companies are an appropriate comparable group. Further, when Hadaway updated his DCF analysis in May 2001, he did not include an updated analysis of gas distribution companies. We do not use gas distribution companies as a proxy for PacifiCorp in our analysis.

[32] Originally, Hadaway had 16 comparable electric companies. By May 2001, only 14 electric companies met the same screening criteria.

Hadaway used both a single-stage (constant growth) and a multi-stage (non-constant growth) DCF model.

For the single-stage DCF analysis, Hadaway averaged the high and low stock prices for each of the three months ending March 2001 for each company in the comparable group as the stock price.[33] He used this higher calculated stock price in his analysis rather than using lower single-month prices from *Value Line*.[34] For D_1, Hadaway used the forecasted 2001 dividend.

Hadaway provided a projected growth analysis by determining the percentage of earnings retained by each comparable company (b) and the rate of return investors expect to earn on each comparable company's book value (r). This calculated figure was then averaged with the mean "5 Year Growth Estimate" as reported by Zacks Investment Research and the "Estimated 97-99 to 03-05 Earnings Growth" as reported by *Value Line* to determine an average growth rate. Finally, an average ROE was calculated by adding the dividend yield to the average growth rate.

For the multi-stage DCF analysis, referred to as the "market price model,"[35] Hadaway used current and forecasted earnings per share, current and forecasted dividends, and current prices. Using this information, Hadaway derived the calculations used to provide the estimates from his model.

Using the electric utility comparable group, Hadaway's single-stage DCF cost of equity average is 11.5 percent, while his multi-stage DCF cost of equity average is 11.3 percent.[36]

Staff presents a total of three DCF models: Conway's single-stage model and Rothschild's single-stage and multi-stage models. Conway applied his single-stage DCF analysis to a sample of 42 electric utility companies that he believed were suitable for use as a proxy cost of equity estimate for PacifiCorp.[37] His sample was limited to companies covered by the *Value Line* Investment Survey that are primarily engaged in retail sales of electricity, companies that have not omitted an annual dividend in the past five years and for whom *Value Line* is forecasting continued dividend payments; and companies for whom he could calculate CAPM betas.

To compute his yield component, Conway used reported stock prices for January 11, 2001, and *Value Line* forecasts of dividend per share for each company for

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[33] By using the calculated higher average price in his analysis rather than the *Value Line* single month price, Hadaway's DCF cost of equity estimate was lowered slightly.
[34] *Value Line* is a widely circulated subscription service that provides independent analysis of stocks.
[35] Hadaway initially presented a third DCF model entitled "Transition to Competition." Upon consideration of Rothschild's testimony, Hadaway agreed that his stage 1 growth in this model was aggressive. Hadaway, in essence, withdrew this model and its results from consideration in this case.
[36] PPL/516, Hadaway/1.
[37] Conway revised the number of companies to 11 in his surreburral testimony of May 2001.

the next 12 months. To estimate future growth, Conway used past dividend growth as an indicator of the marginal investor's expectations of future growth. For his sample of electric companies, Conway examined both the arithmetic and geometric means across the sample of historical dividend growth. Conway's single-stage DCF analysis produces a cost of equity estimate between 7.75 and 8.0 percent.[38]

Rothschild applied his single-stage DCF analysis to three sample groups: a group of electric companies selected by PacifiCorp, a group of gas distribution companies selected by Pacificorp, and a group of water companies that Rothschild selected.

Rothschild considers dividend yield data at a recent point in time and over the last year. First, he calculates dividend yield by dividing the most current annualized dividend rate declared by each company by the spot stock price as of February 28, 2001 for each company. He also divided the most current annualized dividend rate declared by the average high and low stock price of each company over the year ended February 28, 2001. He increased the dividend yield result by adding one-half the future expected growth rate so that the yield is equal to an estimate of dividends over the next year.

To calculate a growth rate, Rothschild uses a $br + vs$ formula. He calculates b, the retention rate, based on a derived dividend yield on book value. To determine r, Rothschild examined both analysts' forecasts and historical data for returns on book equity. Finally, he uses *Value Line* forecasts for his vs inputs.

Rothschild's simplified DCF results produce a cost of equity range of 9.17 to 9.24 percent for the PacifiCorp sample electric group, a range of 9.30 to 9.35 percent for the PacifiCorp sample gas distribution group, and 9.21 to 9.32 percent for the sample water group.

In his multi-stage DCF model, Rothschild separated dividend growth into two stages. His first stage of the model is based on *Value Line's* forecasts for earnings per share and dividends per share for 2000 through 2004. Because *Value Line* does not forecast a specific earnings and dividend projection for every year in that period, Rothschild projected those omitted years by extrapolating the available data.

Rothschild determined second stage earnings by multiplying the future book value per share by the future expected return on book equity used to calculate future growth, g, in his single-stage DCF model. Rothschild projected growth in his second stage for 40 years into the future. Rothschild's complex DCF results produce a cost of equity range of 9.71 to 9.81 percent for PacifiCorp's sample group of electric utility companies.

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[38] In May 2001, Conway calculated an alternative single-stage DCF using his revised list of companies. This resulted in a range of COE estimates from 8.0 percent to 8.2 percent.

Disputed DCF Issues

Of the two DCF versions presented, the parties differ the most with regard to the single-stage DCF model. Specifically, the parties disagree significantly on the proper method to calculate the growth component. PacifiCorp criticizes Conway's single-stage DCF estimate, because he uses historical data to estimate the growth rate component. While Rothschild uses the $br + vs$ formula, PacifiCorp claims that Rothschild's estimates for retention ratios, b, and return on book equity, r, are highly subjective, downwardly biased, and flawed. Staff contends Hadaway determined the value of retention rate b as if it were a totally independent factor rather than a variable that is interrelated to other input values in the DCF formula.

Staff and Pacificorp agree that the single-stage version of the DCF model can only be properly used if dividends, earnings, stock price, and book value are expected to grow at the same rate. The difficulty arises, however, in selecting the values to use for these inputs.

We have previously favored use of the multi-stage DCF analysis over the single-stage DCF formula. In docket UG 132, *In re Northwest Natural Gas*, we noted that the multi-stage DCF improves on the implicit assumption in the single-stage version that dividends grow indefinitely at the same rate.[39] This limitation of the single-stage DCF model is even more significant given the ongoing restructuring of the electric industry. For this reason, and in light of the parties' disagreements over the proper application of the single-stage DCF model, we reject the use of a single-stage DCF analysis in this docket. We conclude that the parties' single-stage DCF analyses provide no information not already contained in their complex DCF analyses. While parties are free to use the single-stage version in future dockets, they will be expected to show that the required industry stability is present.

Turning to the multi-stage DCF models presented, Pacificorp contends that Rothschild's recommendation of a single-digit ROE is based on mismatching data, a disregard of empirical studies, and a series of subjective downward-biased adjustments. Specifially, PacifiCorp claims that Rothschild inappropriately used historical data to lower growth forecasts, mismatched dividend yield and dividend growth information, improperly calculated dividend yields, and mismatched returns on equity, along with retention rates, between his constant-growth and complex DCF models.

First, PacifiCorp criticizes Rothschild's estimate for expected return on book equity, r. PacifiCorp notes that, while Rothschild claims to have relied, in part, on *Value Line* forecasts for the companies in PacifiCorp's sample group, he actually lowers that average by omitting the company with the highest expected return—DPL, Inc. (DPL). Rothschild retained DPL in his sample for the purpose of calculating the dividend yield.

[39] Order No. 99-697 at 23.

Staff responds that Rothschild's exclusion of DPL is justified, because the *Value Line* forecast of a 23 percent return on equity for that company is not indicative of the return investors expect could be maintained into the future. The value of *r* that should be used in the DCR computation is the one that investors believe will be sustainable indefinitely in the future. A dividend yield of 23 percent is not sustainable and should be disregarded. Staff claims that the other numbers for DPL are representative, however, and should be included in the calculation.

Staff is correct that the *Value Line* forecast for DPL is high by historical standards. The issue presented, however, is not whether to include DPL in the DCF estimate, but rather whether DPL data should be used selectively in the analysis. As discussed above, Rothschild excludes DPL to estimate return on book equity, but includes the company to calculate his average dividend yield. This selective use of data overlooks the interrelationship between the various components of the DCF model. Therefore, we include DPL data to estimate the return on book equity and adjust Rothschild's second stage of his DCF calculation. We conclude that Rothschild's expected return on book equity for his second stage of his DCF calculation should be 13.37 percent—the value Rothschild used for the last year (2004) of his first stage calculation.

PacifiCorp also claims that Rothschild erred in calculating the retention rate, *b*. Rather than relying on *Value Line* forecast, Rothschild reverts to a 2001 retention rate for his second stage growth projection. This reversion to the 2001 retention rate, according to PacifiCorp, creates a sharp discontinuity between the first and second stages in his model. PacifiCorp also contends that Rothschild provides no basis to disregard *Value Line* forecasts in his second stage. While Rothschild claims that the current retention rate is "more consistent with investor expectations," he fails to provide any basis for that statement.

In examining Rothschild's calculation of the future retention rate, we are not persuaded that current data should be used instead of forecasted rates. Rothschild fails to support his assertion that the current retention rate seems to better represent investor expectations. Indeed, Rothschild's adjustment causes a steep decline in retention ratios after 2004, reversing an upward trend forecasted by *Value Line*. We concur with PacifiCorp that the use of a forecasted retention rate should be used in this docket. We are not precluding the use of historical retention rate information in future dockets, but parties advocating such usage must justify the use of such data.

PacifiCorp next contends that Rothschild made improper adjustments to the expected return on book equity in the second stage of his DCF calculation. Rothschild initially reduced the expected return on book equity by 75 basis points from stage 1 to stage 2 of his multi-stage DCF analysis.[40] In his surrebuttal testimony, he

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[40] *See*, Staff/1001, Rothschild Schedule JAR 5, page 1, column 11 (reduction from 14 percent to 13.25 percent).

reduces the return on equity in stage 2 by another 25 basis points to 13 percent. The use of 13 percent, according to Rothschild, corrects an error he made previously, and is the number that should have been used as the expected return on equity for the second stage of the multi-stage DCF analysis. This percentage is the one that Rothschild believes is the most accurate for return on equity more than five years from the present. Pacificorp claims that Rothschild subjectively selected this figure to drive down the cost of equity. PacifiCorp argues that Rothschild provides no clear and adequate explanation as to why this number is accurate.

Moreover, Pacificorp claims Rothschild erred in calculating his hypothetical stock purchase. Rothschild uses a figure of $38.47 for the February 28, 2001 average stock price for the utility sample group, when the actual February 28, 2001 average stock price was $36.99.[41] PGE also raised this issue in docket UE 115, and provided further explanation as to the difficulties of Rothschild's use of stock prices. Because we believe the findings in dockets UE 115 and UE 116 should be consistent as to this issue, we take official notice of the testimony, arguments, and conclusions from UE 115 regarding this issue, and incorporate the testimony and conclusions in this docket.[42] Accordingly, we adopt the following from docket UE 115:

> We agree with PGE's observations and conclude that Rothschild's multi-stage DCF estimates should be adjusted so that the average stock price on February 28, 2001 of $36.99 is used for the hypothetical stock purchase. There is no explanation why an investor would irrationally pay $38.47 for a stock that he or she can buy on the market for $36.99. Moreover, because of this adjustment, both the numerator and denominator of Rothschild's M/B calculation should also be modified. For the numerator, Rothschild should have used the average stock price of $36.99; for the denominator, Rothschild should have increased year-end 2000 book values by one-sixth of the increase in the estimated year-end 2001 book values.[43]

2. Capital Asset Pricing Model (CAPM)/Risk Premium

Another method of estimating cost of equity is the risk premium analysis. CAPM is a risk premium analysis that calculates the expected equity return by adding a risk premium to a "risk free" rate of return. Risk is represented by the term "beta," which measures the stock's volatility relative to the market as a whole. The beta for the market is equal to one. Therefore, a stock with a beta greater than one is more risky than the average stock, while a stock with a beta of less than one is less risky than the average stock. The risk premium is generally calculated by multiplying the company's beta by

[41] *See*, Staff/1901, Rothschild Schedule JAR, page 1, column 5.
[42] Pursuant to OAR 860- 014-0050(2), a party may object to the facts noticed within 15 days of this order.
[43] Order No. 01-777 at 29.

the difference between the expected market return and the risk free rate. This formula, designated Equation 1, is generally stated as:

$$k_e = \text{Risk-free rate} + \text{beta (market risk premium)}$$

PacifiCorp submitted another risk premium method similar to CAPM, in which the cost of equity equals the risk free asset plus a company specific risk premium. This formula, designated as Equation 2, is:

$$k_e = RF + CRP$$

Where:

RF = risk-free asset; and
CRP = company-specific risk premium

PacifiCorp made direct estimates of the risk premium for a typical electric utility as the company-specific risk premium in this formula.

CAPM Estimates

Zepp initially presented one risk premium estimate, using Equation 2, and two CAPM estimates. His risk premium analysis assumes that the historical estimates of risk premiums, along with the relationship between risk premiums and the historical level of ten-year Treasury yields, will continue to hold in the future. The risk premiums are determined by using the differences between the historical cost of equity estimates and the cost of ten-year Treasury securities at different points in time during the period 1983 to 1999. A statistical regression is then used to determine the expected relationship between risk premiums and interest rates. This approach assumes that the equity returns authorized by state commissions are, on average, unbiased estimates of equity costs.

Zepp followed a three-step process. First, he estimated a statistical regression of risk premiums on Treasury yields. Next, the regression results were used to estimate a current CRP given a range of consensus forecasts of ten-year Treasury rates for the fourth quarter of 2001.[44] Then the estimated risk premium estimates were combined with the forecasted rates for ten-year Treasury notes to compute the estimated future range of equity costs. As updated by Zepp in May 2001, the risk premium analysis indicated an ROE range of 10.8 to 11.4 percent.[45]

Zepp used the Sharpe-Lintner version of CAPM (Equation 1). This analysis produced an ROE range of 10.5 to 11.7 percent.[46]

[44] Zepp used fourth quarter forecasts, assuming SB 1149 would be implemented in this quarter.
[45] When Zepp used actual rather than forecasted bond yields, a point ROE estimate of 11.4 percent was produced.
[46] This range is much higher than Staff's range. Zepp used different estimates of the risk free rate, beta, and market risk premium than used by Staff.

Zepp also used a "zero-beta" version of CAPM. This version of CAPM is based on the assumption that investors cannot borrow and lend at the same risk-free rate. When using this assumption, the Security Market Line (SML)[47] is flatter than the SML of the original Sharpe-Lintner version of CAPM. This means as beta decreases, the cost of equity decreases by less than the Sharpe-Lintner CAPM model suggests. This is important, according to Zepp, because it means the costs of equity for utilities with betas of less than 1 are closer to the cost of equity for an average risk stock than is shown by the Sharpe-Lintner CAPM model. Under this model, the required return for the risk-free asset is expected to be higher than the return on Treasury bills. By using this version of CAPM, Zepp estimated an ROE of 10.5 to 12.0 percent.

Finally, in rebuttal testimony, Zepp used Staff's alternate zero-beta CAPM, and adjusted it to reflect zero-beta adjustments used in published studies.[48] This adjustment resulted in a CAPM range of 10.9 to 11.3 percent.

Hadaway also presented a risk premium analysis for electric companies. Hadaway compared the average ROEs allowed for regulated electric utilities[49] each year to contemporaneous utility debt costs for the period 1980 – 1999. These studies indicate a risk premium range of 3.72 percent. By adding this risk premium range (3.72 percent) to recent single-A utility debt cost (8.20 percent), the ROE is 11.92 percent.

Staff presents ROE estimates based on the CAPM. Conway's CAPM analysis relies on the traditional formula set forth above. Assuming that investors have intermediate-term investment horizons, Conway calculates a risk-free rate based on an average of intermediate-term U.S. Treasury notes. Averaging the yields-to-maturity of the 5-, 7-, and 10-year U.S. Treasury securities quoted in the April 9, 2001 edition of *The Wall Street Journal*, Conway calculates a risk free rate of 4.6 percent.[50]

Using Staff's traditional Fisher-Kamin method and a new GARCH approach,[51] Conway then calculates a beta for his sample group of electric utility companies of between 0.26 and 0.29. He estimates the sample companies' beta by "regressing" their stock returns—minus a risk-free proxy rate—on the combined portfolio of NYSE/AMEX/NASDAQ stock returns—minus a risk-free rate proxy. In his testimony, Conway notes that his beta calculations may require some subjective adjustment, because they are significantly lower than historical beta estimates. Noting

[47] Required returns increase (the vertical, or "y" axis of a graph) as risk (the horizontal, or "x" axis) increases. This relationship is the Security Market Line.
[48] These studies were conducted by Fama and MacBeth, and reported by Dr. Sharpe in his book *Investments*, Third Edition at 401.
[49] Hadaway also studies gas distribution utilities. As previously stated, we are not considering such evidence in making our determinations.
[50] In his surrebuttal testimony, Conway updated the risk-free rate to 5.0 percent, based on the arithmetic average of the three U.S. Treasury rates listed in the June 20, 2001 edition of *The Wall Street Journal*.
[51] Staff explains that Dr. Curt Wells, Professor of Economics, developed the GARCH approach at the Lund University in Sweden.

that 5-, 7-, and 10-year moving averages for beta estimates are 0.40, 0.42, and 0.44, respectively, Conway believes it is reasonable for the Commission to rely on the longer-term historical beta in this docket.

To estimate the expected market risk premium, Conway assumes that the average market risk premium over a large number of historical intermediate term holding periods is a reasonable estimate of the expected intermediate term market risk premium. He estimates the average historical intermediate term market risk premium by calculating the difference between expected compounded returns on the market portfolio and the compounded returns on the risk free asset over an intermediate period. The difference is then annualized.

To make his estimate, Conway uses monthly returns from 1926 to 1999 for all NYSE/AMEX/NASDAQ stocks as a proxy for the theoretical market portfolio returns. He then estimates the risk-free rate over that period by using 1926 to 1999 data on intermediate-term U.S. Treasury securities. Next, he separates the 1926 to 1999 data into holding periods of five to ten years each, such that all the data were used just once. Finally, he calculates the average rate of return difference between holding the market portfolio and holding the risk-free rate over the intermediate term.

Conway estimates a range of historical market-risk premia of 6.6 to 6.8 percent.[52] Inserting these figures into the CAPM formula with his beta range of 0.29 to 0.44 and a risk free rate of 4.7 percent, Conway estimates a range of cost of capital for his electric utility company sample of 6.6 to 7.7 percent, with a point estimate of 7.2 percent.

Conway also performed a sensitivity analysis assuming both the zero-beta CAPM and an alternative market risk premium as put forth by Dr. Zepp. Conway assumed Zepp's alternative market risk premium of 8.0 and 8.2 percent. Conway then assumed the zero-beta form of CAPM. He indicated that the adder to the risk-free rate called for by the zero-beta CAPM model is 21 basis points, as determined by Rothschild. By multiplying .44 (the electric industry average Fisher-Kamin beta over the past ten years) by Zepp's alternative market risk premium percentages, and adding the updated risk free rate of 5.0 percent and the 21 basis point adder, Conway's updated CAPM resulted in cost of equity ranges of 8.7 to 8.8 percent.

Rothschild uses two different versions of what he calls the "Risk Premium/CAPM method."[53] His first version estimates the cost of equity by quantifying investors' expectation for the future inflation rate and adding a risk premium derived from the difference between the inflation rate and the return on common stocks. In this calculation, Rothschild first estimates the expected rate of inflation to be 2.0 percent by

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[52] Conway also derived market risk premium calculations based on the recommendations of Dr. Pettit, who reviewed Staff's risk premium estimation procedures in 1999. Utilizing Dr. Pettit's recommended approach, Conway estimates the market risk premium to be 4.5 to 4.8 percent. Conway does not rely on these estimates in his CAPM recommendation, however.

[53] Although these can fairly be called risk premium methods, we do not consider them versions of CAPM.

comparing the yields on Treasury bonds with inflation-indexed Treasury bonds. He then adds this 2.0 percent factor to a 6.6 to 7.2 percent historic return on common stocks net of inflation to get an inflation risk premium indicated cost of equity for an investment average risk of 8.6 to 9.2 percent.

Rothschild adjusts this return to account for the lower than average market-risk for the electric utility sample group. To accomplish this, he subtracts the 4.83 percent yield on 90-day U.S. Treasury bills from the historic return on common stocks. He then multiplies this figure by the average *Value Line* beta for the PacifiCorp sample group of 0.53 to derive a 0.94 to 1.26 risk adjusted equity premium. Finally, Rothschild adds this risk adjusted equity premium back to the 6.6 to 7.2 percent range of historic returns on common stocks to derive a 7.77 to 8.09 percent risk premium for the sample group.

Rothschild's second approach to a risk premium/CAPM method was to add a risk premium to the cost of debt based on an increment to the historic annual earned returns. He makes four separate calculations using various interest rates—ranging from 4.83 to 6.71 percent—as his risk-free rate, and various market risk premia—ranging from 3.51 to 5.33 percent. Rothschild then takes the average of these four calculations using both an average risk beta of 1.0 and the *Value Line* beta of 0.53 for electric utilities. Under this methodology, he produces a cost of equity range of 7.60 to 9.55 percent.[54]

Disputed CAPM Issues

We begin with a discussion of the use of CAPM. This Commission has relied on the CAPM as an appropriate method for estimating a utility's cost of common equity for over 20 years. Recently, however, many utilities have argued against its use for reasons similar to those presented by PacifiCorp in this proceeding. To date, this Commission has rejected those arguments, concluding that the CAPM remains a viable method for determining cost of equity.[55]

PacifiCorp claims that Staff's CAPM analysis is below the current cost of electric utility first mortgage debt and is unreasonable on its face. PacifiCorp contends that the low results are caused by the understatement of the risk-free term and an understatement of the applicable market risk premium. PacifiCorp observes that both Rothschild and Conway made numerous ad hoc adjustments to artificially inflate their CAPM results. PacifiCorp claims that Staff's true CAPM results are uniformly below the company's incremental cost of debt, which is in a range of 7.68 to 7.94 percent, the cost of a single A- rated debt utility.[56] PacifiCorp contends that such low results are not

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[54] Rothschild's overall cost of equity recommendation, using single- and multi-stage DCF and his two versions of risk premium/CAPM, is a range of 8.25 to 9.75 percent, with a midpoint of 9.00 percent.
[55] *See, e.g.,* Order No. 99-697 at 19.
[56] *See* PPL/609.

consistent with financial theory, which tells us that the return on a riskier asset, like common stock, should be higher that the return on a less risky asset, like long-term debt.

Staff notes that the CAPM model is a commonly accepted method of determining cost of equity and contends that its CAPM estimates provide important insights into PacifiCorp's cost of equity. Staff acknowledges that the CAPM may be currently understating the cost of equity due to present market conditions. Nonetheless, Staff adds that Conway and Rothschild took this fact into consideration and liberally rounded up the results from their CAPM analyses

We acknowledge that Staff's CAPM methodology faces its biggest challenge yet. Staff cannot escape the fact that its CAPM analyses appear to be producing results below PacifiCorp's current cost of new, long-term debt. While Staff recognizes that the CAPM may be currently understating cost of equity, it is unable to fully explain the significant drop in the Fisher-Kamin betas used in its calculations.[57] It has also failed to convince us that its upward adjustments and rounding of results have accurately and fully compensated for the current CAPM deficiencies.

While the results in this case cast further doubt on the validity of Staff's CAPM methodology, we do not believe that CAPM should be rejected in its entirety. We continue to believe that, in certain cases, CAPM analyses may provide a useful and reliable addition to the DCF results for determining cost of equity. After our review of the results in this case, however, we further conclude that the CAPM does not provide supportable and reasonable results in this docket. Accordingly, we give no weight to the CAPM results in determining an appropriate cost of equity for PacifiCorp.[58]

3. ROEs Authorized by other Regulatory Commissions

In addition to its DCF and CAPM estimates, PacifiCorp relies on recent authorized ROE decisions by other regulatory commissions.[59] PacifiCorp notes that since November 1999, electric utilities received authorized ROEs ranging from 10.00 to 14.14 percent.[60] Because an investor will consider this type of information when making an investment, PacifiCorp believes it should be awarded a common equity return within this range.

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[57] Conway's 0.29 beta is based on data through the year 1999. Using data through the year 2000, PacifiCorp found that the Fisher-Kamin beta for companies in Conway's sample declined to 0.09—a risk figure close to that for U.S. Treasuries that are used as the "risk-free" rate in CAPM calculations.

[58] We acknowledge that PacifiCorp attempted to resolve these difficulties with the use of market risk analysis and alternative forms of the CAPM, such as zero-beta. It is significant to us that Zepp was unaware of any other commission which used this form of CAPM.

[59] On July 19, 2001, PacifiCorp submitted a decision from the Wyoming Public Service Commission approving a stipulation that authorized an ROE of 11.0 percent. We take official notice of that decision.

[60] PacifiCorp presented a list of such awards in its Opening Brief on Capital Structure and Allowed Return on common Equity, pp. 15-17.

Staff objects to PacifiCorp's request that the Commission rely on recent common equity return decisions made in other jurisdictions when setting an authorized ROE in this case. Staff contends that this proposal is circular in reasoning, because decisions would simply be based by looking at what other commissions allow. Staff adds that PacifiCorp's proposal would have the effect of improperly transferring to other jurisdictions the Commission's obligation of setting cost of equity for Oregon utilities. Finally, Staff notes that the Commission rejected a similar request made by NW Natural in docket UG 132:

> NW Natural contends that the Commission should rely on recent common equity return decisions made in other jurisdictions. We disagree. As Staff and NWIGU point out, there is frequently a substantial lag between the time evidence is prepared in a rate case and when a decision is finally rendered. Because interest rates have been steadily declining during the past several years, the failure to account for the regulatory lag could result in an overstatement of cost of capital. Moreover, as noted above, the authorized ROE is just one component of setting rates and is often tied to other, unknown elements in a rate case. Therefore, while other ROE determinations may provide evidence to confirm a decision, we are reluctant to base an award for NW Natural on unknowable parameters from other cases, set in other jurisdictions and different capital market conditions.[61]

We adhere to our prior determination that, while other ROE determinations may provide confirmation of a decision, they should not be used as an independent method on which to base an award. Capital market conditions, not regulatory decisions, determine a utility's cost of equity. While we agree that regulatory agencies generally make every effort to capture those market conditions, a review of past decisions cannot replace an independent analysis of current market conditions and how they affect the particular utility. Moreover, ROE determinations are made not just in traditional rate cases, but also in a range of other proceedings, such as industry restructuring plans, merger approval cases, or performance-based regulatory plans. Thus, the ROE awards may have been based, in part, on other unknown parameters relevant in that particular docket.

Accordingly, we will continue to review ROEs authorized in other jurisdictions to help gauge the reasonableness of the cost of equity estimates derived from independent methodologies. We will not, however, rely on such decisions as the basis for an ROE award for a utility.

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[61] Order No. 99-697 at 23.

4. Qualitative Analysis

Staff's final cost of equity estimate is based on a qualitative analysis that updates the Commission's most recent contested ROE decision. Conway notes that in docket UG 132, Order No. 99-697, the Commission set rates for NW Natural based on a return on equity of 10.25 percent. There, the Commission adopted a market risk premium of 8.5 percent, a risk-free rate of 6.3 percent, and a beta estimate of 0.46, to obtain a CAPM estimate of 10.21 percent. The Commission averaged that estimate with a DCF estimate of 10.21 percent to obtain a 10.25 percent cost of equity.

Updating those figures with new information, Conway presents a range of estimates for PacifiCorp's cost of equity from 8.3 to 10.1 percent. Conway provides this range as an upper bound for ROE estimates.

While recognizing that Conway's update to the Commission's decision in docket UG 132 favors the company, PacifiCorp argues that this analysis should be given no weight for four reasons: 1) electric utility debt costs have increased, so that basing comparisons on an asserted 170 basis point reduction in Treasury rates, as Conway did, is not accurate; 2) this analysis is dependent on the decision selected by the Commission for comparison; 3) this analysis carries forward the impact of Staff's miscalculation of the CAPM market risk premium; and 4) the NW Natural Order is not a reasonable benchmark. PacifiCorp recommends that the Commission disregard this analysis in determining the appropriate ROE in this case.

Staff argues that as PacifiCorp is unclear about its incremental debt costs, it cannot now claim that utility debt costs have risen. Further, there is little mystery as to why UG 132 was selected for comparison, as it is the most recent rate case determination. Corrections were made to any "mistakes" in UG 132. Finally, Staff believes that UG 132 is a reasonable benchmark.

We acknowledge and appreciate Staff's efforts to provide additional analyses for our review of this issue. Nonetheless, we acknowledge that the adjustments included in the qualitative analysis are not sufficiently linked to PacifiCorp to provide a valid cost of equity estimate in this docket. Accordingly, we do not use this analysis in making an appropriate ROE determination.

Commission Resolution

The determination of the cost of equity is not an exact science. As shown by the numerous theories put forth by the parties, and the various ranges calculated by the parties using those theories, there is no one single cost of equity that is the "right" number. Our job is to sift through the information presented, and determine a reasonable cost of equity in this case.

As previously discussed, we reject the parties' single-state DCF calculations, the CAPM and risk premium calculations, the comparison ROEs, and the qualitative analysis. What remains is Staff's and PacifiCorp's multi-stage DCF analyses.

In reviewing Rothschild's multi-stage DCF estimate, we found that certain adjustments need to be made. These involve using the average forecasted retention rate for 2004, using the year 2004 value for expected return on book equity, and correcting inputs for stock purchase price. Once made, these adjustments produce an approximate final DCF of 10.5 percent.

We need not make any similar adjustments to Hadaway's multi-stage DCF estimates. Rather, based on his calculations, we estimate PacifiCorp's final DCF to be approximately 11 percent.

The evidence presented supports that a reasonable cost of equity estimate is in the range of 10.5 percent and 11 percent. We select 10.75 percent, the mid-point of this range, as the appropriate and reasonable authorized return on common equity for PacifiCorp. The evidence shows that this award will allow PacifiCorp to attract capital at a reasonable cost.

Use of this figure, in conjunction with the other previously determined capital costs and the company’s capital structure, yields a rate of return for PacifiCorp of 8.62 percent.

Capital Component	**Percent**	**Cost**	**Weighted Cost**
Cost of Long-Term Debt	45.0%	6.88%	3.10%
Cost of Preferred Stock	8.7%	6.16%	.54%
Cost of Equity	46.3%	10.75%	4.98%
Total	100.0%		8.62%

Finally, as in UE 115, we close with a short discussion on efforts expended in this docket to fix a reasonable ROE for PacifiCorp. As we previously stated:

> ROE determinations have always been a fundamental part of utility regulation and, despite a decline in the frequency of traditional utility rate cases, continue to play an important role in ratemaking. The task of determining a reasonable ROE, however, is often one of the most difficult and contentious aspects of a rate case proceeding.
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> . . .
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> We recognize the inherent complexity of the issue, and that it may be impossible to devise a method to make the process of determining a

reasonable ROE an agreeable one. Others with more time and expertise have tried to establish a consensus on the overall efficacy of ROE techniques and methodologies, but failed. It appears that contention over ROE is unavoidable. Nonetheless, while we recognize our inability to make the ROE process easy, we believe that the adoption of certain principles on this matter will make the process of setting a reasonable ROE easier. Based on our experience in this and in other dockets, we offer guidelines, set forth in Appendix [E], for witnesses providing cost of equity recommendations.[62]

II. Power Costs

The parties were able to reach agreement on all but two of the outstanding power costs issues, and reached agreement on how to handle upcoming net power cost adjustments.[63] We address each in turn.

A. Sacramento Municipal Utility District (SMUD) Contract Adjustment

In PacifiCorp's most recent rate case in Utah, the Utah Commission imputed revenue for a contract between PacifiCorp and SMUD.[64] The Utah Commission found that, in 1987, PacifiCorp had entered into a long-term contract (through 2014) with SMUD, wherein SMUD acquired electricity at a rate of $16.85 per MWh. Although this was a below-market price in 1987, PacifiCorp received an up-front payment from SMUD of $94 million. According to the Utah Commission, the $94 million was retained by PacifiCorp and not used to reduce rates.

The Utah Commission decided to find a rate, contemporaneous with the SMUD contract date, to use as its basis for revenue imputation. The rate used was taken from a Southern California Edison (SCE) contract negotiated at approximately the same time as the SMUD contract.

ICNU, through its witness Randy Falkenberg, proposed an adjustment of $7.8 million due to the SMUD contract. However, rather than using the methodology adopted by the Utah Commission, ICNU chose to remove the sale from the PD-Mac run. ICNU's rationale for this approach was to insulate ratepayers from the cost of the contract, while allowing PacifiCorp to keep any potential future profits.[65]

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62 Order No. 01-777 at 36-37.
63 See discussion under "Power Cost Stipulation" beginning on p. 11.
64 Utah Public Service Commission, Docket No. 99-035-10.
65 ICNU believed that a $7.8 million adjustment is "roughly comparable" to the result obtained if the SCE price were used. However, to reach the amount suggested by ICNU using the SCE contract, this Commission would have to figure the imputed revenue from a renegotiated contract between SCE and PacifiCorp with higher prices, not the original contract between the two parties.

PacifiCorp contends that ICNU's proposed adjustment provides a much higher level of benefits to customers than they would have received had PacifiCorp initially sold the power to SMUD at 1987 market prices. Further, the stipulation reached by PacifiCorp and Staff reflects the appropriate adjustment of $2,751,000.[66] This stipulated adjustment imputes additional wholesale revenues associated with sales to SMUD in recognition of the capacity value provided to SMUD through the sale. PacifCorp asks the Commission to reject ICNU's adjustment.

Commission Resolution

We agree with PacifiCorp that the stipulation reached with Staff appropriately imputes the amount of revenue to be recovered. Because we have adopted the net power cost stipulation, we do not wish to entertain an argument based on "backing out" a cost from the PD-Mac model. Further, the only way to compute a $7.8 million adjustment using the SCE contract is to use a renegotiated figure from a later contract, and not the initial figure in the original SCE contract. We decline to do so. We are satisfied with the rationale of the PacifiCorp and Staff stipulation on this issue.

B. Western Area Power Administration (WAPA) Wheeling Contracts

This is another issue raised by ICNU on which the Utah Commission has issued an order.[67] In 1962, Utah Power and Light entered into a fixed rate contract for 80 years with the United States Bureau of Reclamation (later known as WAPA) to wheel Colorado River Storage Project (CRSP) power over the company's transmission system to public power preference customers. Some years later, Utah Power purchased CP National Corporation's Utah system, and acquired a wheeling contract between CP National and the Bureau which had the same purpose and wheeling rate as the Utah Power contract. The wheeling rate in these contracts is $4.20 per kilowatt-year. Neither contract permits escalation.

In 1983, the Utah Commission recognized that the contracts were not compensatory and ordered imputation of revenues, based on the then-current FERC wheeling rate of $24.12, to prevent the subsidy that otherwise would flow from Utah Power's retail customers to CRSP preference customers.[68] Utah's policy has been to impute revenue since that time.

ICNU proposes a $2 million adjustment to the Company's revenue requirement based upon the current FERC wheeling rate and PacifiCorp's filing in Utah. ICNU argues that these contracts were imprudent when signed because they failed to include a process to compensate PacifiCorp for increasing costs of service and that a subsidy is flowing from retail customers to preference customers.

[66] See Stipulation at Appendix A.
[67] Docket No. 99-035-10.
[68] Utah Pubic Service Commission Docket 82-035-13, Report and Order issued May 23, 1983.

PacifiCorp argues that the adjustment should not be made for two reasons.[69] First, PacifiCorp claims that ICNU is asking this Commission to selectively rewrite terms of PacifiCorp's long-standing contracts for ratemaking purposes. According to PacifiCorp, this violates the principle that contracts are to be evaluated for ratemaking purposes based upon the conditions that existed at the time a contract was executed.

Next, PacifiCorp claims that ICNU's adjustment completely ignores the benefits that the single company-owned transmission system has delivered to customers over the years. According to PacifiCorp, the long-term wheeling contract forestalled the construction of a duplicative transmission system in Utah. This allowed PacifiCorp to capitalize on its location between low-cost supplies in the Northwest and high-cost supplies in the Southwest, and generate revenue from wheeling, low-cost purchases, and surplus sales that have been used to offset rates charged to customers.

Finally, PacifiCorp urges the Commission not to "acquiesce" to the Utah Commission ruling, and make its own decision based on an independent evaluation of the arguments.

Commission Resolution

We agree with PacifiCorp that it would not be appropriate to reevaluate an historical transaction based on current cost levels. However, it is appropriate for us to be concerned about retail customers subsidizing contracts such as these. As we read the portion of the Utah Commission decision provided to us, Utah had the same concern and acted on it in 1983.

PacifiCorp claims that customers received benefits from these wheeling contracts that offset rates. The testimony, however, does not quantify those benefits, but rather simply states that they occurred. We do not know whether or not these "benefits" offset the subsidy provided by retail customers. The evidence provided is not persuasive on this issue.

We hold that an adjustment needs to be made for the WAPA wheeling contracts. PacifiCorp claims, however, that the record does not support an amount for the adjustment as ICNU did not provide any evidence of its proposed $2 million adjustment. We disagree. Falkenberg's testimony states that the Utah Commission imputed revenue to the contract based on the current FERC wheeling rate. He further states:

[69] In its brief, PacifiCorp raised a third reason for not allowing the adjustment. PacifiCorp claims that ICNU did not provide any support for the specific adjustment amount of $2 million, and should be disallowed as a failure of proof. We discuss this issue in our resolution of the matter.

> Based on [PacifiCorp's] filing in Utah, this would result in a disallowance of $2.0 million for Oregon.[70]

It is reasonable to presume from this evidence that by using the Utah formula with the current FERC wheeling rate, the Oregon adjustment should be $2 million. We adopt this amount as the adjustment to be made regarding these wheeling contracts.

III. Traditional Issues

In this section, we respond to all of the remaining revenue requirement issues and other traditional ratemaking issues raised by the parties. We also include any other miscellaneous issues raised in this docket.

A. Test Year

ICNU claims that the Commission should either reject or modify PacifiCorp's projected test year because it does not provide an accurate basis for determining PacifiCorp's revenue requirement. Staff argues that PacifiCorp misapplies the Commission's decisions about the use of a test year. PacifiCorp contends that adjustments proposed by other parties should not be made, because it is using a forecasted year, not an historical test period, as required by the Commission.[71]

PacifiCorp used calendar year 2001 as its test year, and forecasted from year-end 1999 expenses. The difficulties arose because year-end 2000 expenses, and some 2001 expenses, were known for several categories by the time hearings were concluded in June 2001. The record contains information about these expenses. It makes little sense to us to disregard actual results, particularly when those results do not match with PacifiCorp's forecasts. In light of this, we will make adjustments as we see fit based upon known changes and data in 2001. The adjustments, if made, will be discussed in the appropriate revenue requirement sections set forth below.

B. Revenue Adjustments

Staff, ICNU, and CUB propose revenue requirement adjustments. We address each proposed adjustment by party. We conclude this section with adopting an overall revenue requirement.

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[70] ICNU/200, RJF 21, lines 3-4.

[71] OAR 860-038-0200(6) requires an electric company to make an initial filing which "shall use the financial results for a test year that encompasses all or part of the 12-month period beginning October 1, 2001."

1. Staff Adjustments

As previously discussed, Staff and PacifiCorp entered into a partial revenue requirement stipulation. The following are the unresolved Staff issues:

S-10 Wages and Salaries

This issue involves how to make a reasonable test-period estimate for PacifiCorp's wages and salaries. The dispute arises over the models and processes to be used for making the wages and salaries estimate.

Rather than using 1998 as its base period, Staff used data from 1999. Staff calculated the 1999 average salary by dividing the 1999 annualized payroll by the average number of FTE.[72] Using the 1999 average salary, the Consumer Price Index (CPI) – All Urban Consumers percentage change of 5.67 over a two-year period (1999 and 2000) and the 1999 number of employees, Staff determined a projected payroll for 2001. As Staff's projected payroll for 2001 was greater than PacifiCorp's projections, Staff's methodology provided for the customers and stockholders to share the difference. This resulted in total O&M adjustments of $307,912; a rate base adjustment of $117,484 and a payroll tax adjustment of $8,283.

PacifiCorp also proposed to use 1999 data from which it removed all labor costs caused by the sale of the Centralia plant, along with incentives and severance costs. Next, PacifiCorp computed an escalation factor by using contract wage increases. The increase resulting from use of this factor was compared to 1999 base labor, which produced a weighted-average increase for the total company. This weighted factor was then applied to escalate labor costs in 1999 and 2000 to obtain a 2001 test-year estimate.

PacifiCorp argues that Staff is deviating from its traditional three-year model, used by the Commission for over 15 years, without sufficient cause. Further, it argues that as its actual payroll is increasing faster than inflation, Staff's choice of using a base year closer in time to the test year will likely cause a larger decrease to test-year payroll than a three-year model. According to PacifiCorp, the Commission should either adopt PacifiCorp's proposed wage and salary adjustment, or not make any adjustment.

Generally, Staff uses a three-year model to forecast appropriate test year expenditures, with the model base year being three years prior to the test year. If a three-year model was used, information from calendar years 1998 through 2000 would be used, with 1998 labeled as the "base" year.

[72] PacifiCorp's FTE number was reduced by 150 due to the Centralia plant sale. Staff's revised Ex. 402 did not include those employees in its calculation.

Staff recommends in this case, however, that the Commission use a two-year model, with 1999 as the base year. Staff's rationale is that the purpose of a base year is to provide stability to the model. For PacifiCorp, 1998 was not a stable year for treatment of wages and salaries. In 1998, an early retirement program was implemented which reduced the number of FTE's by the end of the year. However, the 1998 data is distorted, as it took almost the entire year to complete the employee reduction, resulting in a larger salary per FTE.[73]

The purpose of a model is to provide information that can reliably be used to estimate expenses for wages and salaries. If information in the model is faulty, then the value of the information provided is suspect. While we try to maintain consistency as to the models we use, there are times when the information available means that we need to vary the model. This is one of those times.

We do not agree with PacifiCorp's claim that it is simple to remove the costs of the early retirees to produce an adjusted figure. During 1998, payroll costs and FTE numbers changed monthly. A methodology based on an annualized payroll and year-end number inputs, inputs which are not representative of the entire picture, will produce information of little value.

Staff has presented compelling arguments for using 1999 as the base year.[74] This does not mean that we have changed our preference for using a three-year model. Rather, the circumstances of this case dictate that using the two-year model will provide more reliable estimates than using the standard three-year model.

Using 1999 as the base year, we turn to the issue of what is the appropriate escalator to be used to obtain 2001 estimates. Staff's model presumes that the salaries and wages as they existed in 1999 are reasonable and applies a CPI figure to escalate salaries. PacifiCorp uses a methodology that incorporates projected increases of four percent per year on adjusted 1999 salaries.

We agree that the increase in payroll should be tied to the rate of inflation (CPI). Using the CPI in conjunction with the Staff recommendation of sharing the difference allows PacifiCorp an average salary change of approximately 6.62 percent compared to PacifiCorp's request of 8.16 percent.

Staff's adjustments are adopted.

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[73] An annualized payroll expense includes the salary costs for persons no longer employed by the company at the end of the year. This number, divided by a low number of year-end FTE, would result in a higher average salary per FTE.

[74] We note that PacifiCorp also started with a 1999 base year.

S-12 Manpower

The parties apparently agree that the customers should get the benefits of any manpower savings. This agreement is shown by the manner in which PacifiCorp and Staff handled the Centralia closure. The made an adjustment to employee numbers to reflect the loss of those employees. The unresolved issue here is how to handle the loss of employees due to Transition Plan downsizing.

Staff adjusts the 1999 manpower levels used in PacifiCorp's filing to actual levels at December 31, 2000. Staff uses the actual year-end 2000 numbers because it believes these reductions are permanent and should be recognized in base rates.[75] Staff's adjustment recognizes both the actual reduction in employees and the severance costs associated with the loss of the employees. The net effect is a $4.427 million decrease in O&M expense and a $13.730 million increase in rate base. The revenue requirement effect is a reduction of $3.013 million.

Initially, PacifiCorp proposed a Transition Plan Adjustment in this case. However, the adjustment would have resulted in an increase in revenue requirement, which is a violation of Condition 10 of the ScottishPower/PacifiCorp Merger Agreement approved by the Commission. So Staff and PacifiCorp agreed to exclude this adjustment.[76]

PacifiCorp argues that Staff's adjustment captures a component of the Transition Plan adjustment while avoiding the full costs. According to PacifiCorp, when the ten-year costs associated with the employee departures are matched against the savings and amortized, there are no net savings. Amortizing the costs on a 10-year straight-line basis is consistent with the Staff recommendation adopted by the Commission in its order permitting PacifiCorp to defer Transition Plan costs.[77] To allow the recovery of these costs as employees leave the Company violates the Commission's intent for the ratemaking treatment of these costs. PacifiCorp argues that Staff is imputing additional savings relating to employee reduction on top of the $12 million merger credit and the absorbed costs of the transition plan.

In testimony regarding another revenue adjustment issue, legal costs, the attorney for ICNU asked Mr. Jeffrey Larsen, Director of Revenue Requirement for PacifiCorp, the following:

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[75] Manpower levels at the end of 1999 and 2000 were 6,325.5 and 5,833.5, respectively. This lower manpower level in 2000 is attributed to the effects of PacifiCorp's Transition Plan.

[76] PacifiCorp is under the impression that its agreement with Staff to remove the Transition Plan Adjustment (Appendix A, S-16) resulted in an understanding with Staff that the rate recovery of deferred severance and retirement costs would be postponed until the transition plan benefits would at least equal the amortization costs. While there may have been confusion on PacifiCorp's part, the stipulation clearly labels "S-12 Manpower Adjustment" as an issue to be resolved in this order.

[77] *In re PacifiCorp*, UM 978, Order No. 00-406 at 1.

> Q. . . . Isn't there an assumption, however, that when PacifiCorp comes in and files a rate case even during this merger credit time period, that the rates should reflect the actual costs, including actual savings, that may be incurred as a result of the transition plan; isn't that correct?
>
> A. I think that's exactly what I've been saying.[78]

The issue, then, is not *whether* the actual costs and savings from employee reductions should be recovered, but rather in what manner those reductions should be captured. PacifiCorp would have us wait, while Staff argues for making the adjustment now.

We agree with Staff that due to the reduction in employees because of PacifiCorp's downsizing, we should utilize the actual employee numbers as of December 31, 2000. We also agree with using Staff's methodology for making the manpower adjustment. This adjustment is not uncommon in a rate case. What makes it arguably unique in this case is PacifiCorp's deferral based on its Transition Plan. However, PacifiCorp's methodology would allow it to amortize and collect revenues for costs not yet realized. We do not consider that an appropriate ratemaking expense.

Staff's adjustment is adopted.

S-14 1987/88 Pension Amortization

This issue addresses how costs associated with early retirement programs in 1987 and 1990 should be treated.

PacifiCorp wants to amortize the unfunded portion of its pension costs ($86,877,000) that were stranded by its change in pension accounting conventions in 1997 when it went from a cash to an accrual basis. Prior to the change, a deferred pension asset was created for the difference between the amount of funding in the pension plan and the total pension cost. This deferred asset would self-amortize as the pension plan was fully funded.

Staff contends that the entire amount should be disallowed, resulting in a $5.640 million reduction to PacifiCorp's O&M expenses, and a $7.494 million decrease to rate base. These costs are "old costs" that previously have been written off by PacifiCorp. Staff also claims that these are not actually pension costs, but are merely the effect of a change in accounting methods.

[78] Tr.at 63, lines 9 – 15.

These costs should not be allowed. PacifiCorp wrote them off in 1997, and did not attempt to recover them during earlier filings.

We adopt Staff's adjustment.

S-15 Pension

At the time of hearing, PacifiCorp had agreed that a $19 million adjustment needed to be made due to an error of double-counting this expense. Staff, however, thought the error was $20,635,000. During the briefing process, PacifiCorp and Staff were able to resolve this issue, and agreed that an adjustment of $20,142,000, decreasing PacifiCorp's projection of 2001 Pension and Benefits expenses, should be made. We adopt this adjustment.

S-18 Sales and Marketing

This dispute involves whether a $3,290,000 expense is a customer service cost, or a sales and marketing expense.

PacifiCorp claims that this is a cost associated with its Regional Community Managers (RCMs) and Corporate Account Managers (CAMs) programs. A CAM is assigned to work with a single customer to solve problems. RCMs work with cities and towns, along with other commercial and small industrial customers not assigned to a CAM. PacifiCorp reclassified these expenses so as to distinguish expenses related to one-on-one accounts rather than general customer service expenses. PacifiCorp argues that the "character of the costs" are customer service costs, even though it filed these expenses in FERC accounts that are sales and marketing cost accounts.

Staff's position is that these costs should be excluded as sales and marketing expenses for which PacifiCorp has not shown a net ratepayer benefit. The purported rationale for PacifiCorp reclassifying these expenses to FERC 912/916 accounts was to move “sale expenses” to correct accounts.

PacifiCorp made its FERC filing claiming that these expenses fit the FERC definitions, which are clearly sales and marketing definitions. While it is possible that these expenses are “customer service” costs, this is not how PacifiCorp categorized the costs with FERC. We do not think it a wise course for us to allow PacifiCorp to recharacterize its FERC filing and have us "second-guess" the true meaning of the expenses. Of course, PacifiCorp can, in the future, change how these expenses are characterized with FERC. The expense is disallowed.

S-23 Supplemental Executive Retirement Plan (SERP)

SERP was established to compensate executive employees for the difference between PacifiCorp's qualified defined pension benefit and 60 to 70 percent of the employees' final average salary. SERP, according to PacifiCorp, is a necessary form of compensation for its executives. Based on a survey of 40 utilities surveyed by PacifiCorp, more than 70 percent of the utilities offer SERP. PacifiCorp argues that SERP costs should not be removed.

Staff proposes to remove the entire cost of SERP, approximately $806,000 from the revenue requirement. Staff argues that PacifiCorp's executives are already well compensated, receiving on average 4.3 times the average compensation of non-officers. Further, these executives are already covered by a regular retirement plan, the expense of which is covered in customer rates. Finally, PacifiCorp did not establish that SERP was a necessary expense.

The Commission has not allowed recovery of SERP expenses in other utility rate cases. PacifiCorp has not persuaded us that it is necessary to pay SERP to hire and retain executive officers. The SERP costs are not allowed.

S-41 Environmental Settlement

PacifiCorp received an insurance settlement, the proceeds of which are to be used for environmental clean-up projects. The fund amount fluctuates due to expenditures for clean-up projects and additional proceeds from other insurance settlements. While the balance in the account must be used to offset PacifiCorp's revenue requirement, Staff and PacifiCorp disagree as the methodology to be used to estimate the account balance on December 31, 2001.

PacifiCorp recommends that the 2001 environmental expense level be based on the most recent three-year average of these expenses (1998-2000). Based on this calculation, the estimated 2001 fund expenditure would be $2,696,000.

Staff used actual fund expenditures for 2000. Its estimate of $2,320,000 for 2001 expenditures was calculated by averaging the actual and budgeted expenditures for a 15 year period from 1997 – 2011.[79] Finally, Staff subtracted the actual 2000 expenditures, along with the estimated 2001 expenditures, from the fund balance as of December 31, 1999 to produce a December 31, 2001 fund balance estimate.

We agree with Staff's methodology for computing the estimated expenses for 2001. PacifiCorp's estimated 2001 fund expenses are considerably higher than any

[79] For years 1997 through 2000, actual expenditures were used. For years 2001 through 2011, PacifiCorp budgeted expenditures were used.

other year from 1997 to 2011. PacifiCorp claims that this additional expense is due to the number of projects it is working on in 2001. The record, however, does not contain information as to whether these expenses have actually been incurred.

We adopt Staff's adjustment.

Amount and Amortization of SB 1149 Costs

By letter dated July 19, 2001, PacifiCorp agreed to Staff's proposal, recovering in this docket only those implementation costs that PacifiCorp has expended by March 31, 2001. This amounts to the inclusion of $5.4 million for SB 1149 implementation costs. This amount is significantly less than the initial estimated amount of $25 million that PacifiCorp expected to spend by October 1, 2001.

PacifiCorp wants to amortize these expenses over a five-year period, while Staff believes that some of these expenses should be amortized on a different schedule. While we do not disagree with Staff's premise that capital expenses should be amortized for their useful life, in this particular instance we agree that the easiest way to handle this expense is to amortize it for five years on a straight line basis. For SB 1149 expenses not captured by the $5.4 million expense, however, PacifiCorp must give Staff sufficient time to audit the expenses and determine an appropriate amortization schedule. Therefore, PacifiCorp must submit its SB 1149 expenses incurred since March 31, 2001 by February 1, 2002.

2. ICNU Adjustments

PacifiCorp previously conceded to some proposed revenue adjustments by ICNU.[80] ICNU joins Staff in all of Staff's adjustments, except for sales and marketing (S-18) and the environmental settlement (S-41). In addition, ICNU proposes adjustments in the following areas:

Business System Integration Project (BSIP/SAP)[81]

PacifiCorp incurred a total SAP expense of approximately $14.3 million in 1999. This expense is broken down as follows:

- $3.4 million for company employee salaries. Employees were loaned to the project from their regular work assignments. At the end of the project, the employees

[80] These adjustments are: Annual report ($67,660); Retail Marketing Software ($6,159 O&M; $33,942 amortization; $585,810 rate base); and Director's Fees ($211,200).

[81] Staff and PacifiCorp addressed this issue in S-39, I.T. Rate Base Disallowance, of their partial revenue requirement stipulation. They agreed to an adjustment allowing 90 percent of PacifiCorp's SAP costs for ratemaking purposes.

returned to their regular positions. PacifiCorp did not backfill many of the positions during the project.

- $4.9 million for operation and maintenance of the system, which did not include $2.6 million of internal labor.

- $6 million for training, which did not include internal labor of $0.8 million. After the completion of the project, the training emphasis shifted to other needs.

PacifiCorp claims that these costs are necessary, on-going expenses, which should not be eliminated as nonrecurring costs.

ICNU proposes an approximate $9.9 million reduction in BSIP/SAP costs, claiming that PacifiCorp has proposed recovery for 1999 program start up costs that are nonrecurring. Specifically, ICNU disagrees with PacifiCorp that the $3.4 million for salaries and $6 million in training is an on-going expense. ICNU also claims that the $0.6 million of the system operation and maintenance expenses should be reduced, leaving $4.3 million in recurring costs.

CUB joins in ICNU's adjustment, but indicates an appropriate reduction is $6.8 million.

PacifiCorp adequately explained the breakdown and the on-going nature of its costs related to BSIP/SAP. We do not find these costs to be nonrecurring, as claimed by ICNU and CUB. Further, the Staff/PacifiCorp partial revenue requirement stipulation recognizes a $797,000 reduction in SAP expenses. This stipulated amount is a reasonable reduction to these expenses. We therefore do not adopt the adjustments proposed by ICNU and CUB.

Customer Service System (CSS) Costs

PacifiCorp's CSS was designed in the early 1990s. PacifiCorp's Powercor subsidiary analyzed the CSS in 1999 and determined that the system would not meet business requirements without significant modification, as it was unable to support foreign operations. According to PacifiCorp, the modifications made to the system do not reflect that it is more expensive than necessary, as ICNU contends. Rather, the ability of the system to handle additional data is due to the database's architecture, and came at no additional cost to PacifiCorp. The current system and hardware are optimally sized to handle the current customer base, the historical data, and the normal projected customer growth. Finally, PacifiCorp argues that the system cost per customer, which is $44.91, is lower than the average cost of customer information systems, which was $49.75, found by Staff in their review of 17 systems.

Claiming that PacifiCorp has an oversized system, ICNU proposes a $900,000 reduction along with excluding $8.3 million from the rate base. ICNU contends that the system was over-built in anticipation of PacifiCorp's growth through acquisition. According to ICNU, PacifiCorp does not need this large of a system to serve its customers.

Further, Staff reviewed PacifiCorp's CSS costs, and determined to allow 100 percent of the CSS costs for ratemaking purposes.[82]

ICNU did not establish that PacifiCorp devised a CSS that was too large, or that PacifiCorp incurred unnecessary expenses in building its system. While the system has capabilities greater than PacifiCorp's current needs, these capabilities did not come at additional cost to PacifiCorp. Further, the evidence reflects that PacifiCorp's per customer cost is less than the average cost of other utility customer information systems.

Legal Costs

ICNU proposes a reduction ($2.0 million total system; $600,000 on an Oregon basis) in costs associated with attorney fees. ICNU contends that PacifiCorp is planning on a $2.0 million reduction in legal costs as identified in the Transition Plan.

PacifiCorp argues that these reductions should not be incorporated into the 2001 test year as these savings have not yet occurred. Further, although PacifiCorp plans to cut its legal expenses in the future, no action has been taken on the plan. PacifiCorp does not know if the anticipated savings will actually occur.

PacifiCorp also argues that the merger credit is intended to reflect the potential savings in legal costs. To further reduce PacifiCorp's costs would be "double-counting" and punitive in nature.

In the issue involving a manpower adjustment, we were faced with implementing reductions that have already occurred. In this instance, ICNU asks us to reduce these costs based on PacifiCorp's *plan* to reduce legal expenses. This reduction is due to occur as part of the Transition Plan, although we do not know whether such reductions will actually occur. We agree with PacifiCorp that this is the type of situation that is addressed by the merger credit. It is not appropriate to take additional legal cost reductions at this time.

We do not adopt ICNU's proposed reduction to legal expenses.

[82] Testimony in Support of Partial Revenue Requirement Stipulation, Staff-PacifiCorp/100, Johnson-Hellebuyck/8, lines 1-5.

New York Stock Exchange Charges

PacifiCorp has included stock-listing costs, which ICNU claims should be disallowed. These costs, amounting to $83,403, are ScottishPower American Depository Receipts (ADRs). These trade publicly on the New York Stock Exchange (NYSE).[83] Nearly 90 percent of the former PacifiCorp shareholders opted for the ADRs. Therefore, the cost of servicing ADRs is considered a PacifiCorp expense. PacifiCorp also pays the listing fees. According to PacifiCorp, the cost of listing the ADRs on the NYSE is an on-going expense.

PacifiCorp agrees, in concept, that such costs would be best handled through a corporate overhead allocation. However, such a system for allocating ScottishPower overheads is not yet in place. In general, as the ADRs listed in New York represent pre-merger PacifiCorp shareholders, using the cost of listing ADRs on the NYSE is a reasonable proxy for PacifiCorp's allocated share of all stock listings. Therefore, PacifiCorp argues that no reduction should be made.

ICNU proposes an adjustment of $83,403 based on the cost of listing the ADRs on the New York Stock Exchange. ICNU initially claims that these costs are nonrecurring. ICNU further claims that these listing costs are ScottishPower's responsibility to be allocated to all of its companies, rather than the sole responsibility of PacifiCorp. CUB joins ICNU in proposing this adjustment.

ICNU and CUB contend that these expenses are nonrecurring, and should be allocated to all ScottishPower companies. The evidence is clear that these are recurring expenses. The question becomes whether the proxy adopted by PacifiCorp is a reasonable proxy for determining allocation. Although we would prefer an actual overhead allocation method of ScottishPower expenses, we cannot say that PacifiCorp's use of the ADRs as a proxy for its stock market charges is unreasonable. These expenses are allowed.

Temporary Labor

Staff and PacifiCorp reduced the temporary employee expense by $618,000, as set forth in issue S-32 of the partial revenue stipulation.

ICNU agrees that the PacifiCorp-Staff Partial Stipulation partially addresses ICNU's concern. However, that stipulation used a five-year average (1995-1999). ICNU proposes excluding 1998 and 1999 expenses, which it believes are abnormally high, and using a 1995-1997 average. This would result in an additional reduction of $782,000.

[83] Shares of ScottishPower, on the other hand, trade on the London Stock Exchange and are denominated in pounds sterling.

ICNU argues that PacifiCorp has not proven that the 1998 and 1999 costs are reasonably certain to recur or are prudent. Its concern is that PacifiCorp terminated employees during its "Refocus Program" in 1998 and 1999, and eliminated additional jobs in the first year of its Transition Plan (2000), but incurring a greatly increased cost in temporary labor.[84]

As the Transition Plan did not begin until 2000, PacifiCorp claims that the Transition Plan had no effect on these costs. PacifCorp also contends that the stipulated adjustment addressed any "unrepresentative" 1999 temporary employee costs. According to PacifiCorp, this expense should not be further reduced.

The record contains no explanation for the increase in use of temporary employees from 1998 to 1999. Further, we have no indication that the temporary employee expenses will continue at the 1999 level. However, Staff and PacifiCorp attempted to mitigate this spike by using a five-year average for the 1999 figures rather than using actual 1999 figures. We find that this method provides a sufficient adjustment of $618,000 as set forth in the stipulation in Appendix A. We do not adopt any additional adjustments to this expense.

Revenue Requirement

Adjustments were made, consistent with Staff recommendations, to wages and salaries, manpower, 1987/88 pension amortization, sales and marketing, SERP, and environmental settlement. Additionally, the parties agreed to adjustments to pensions, SB 1149 costs (through 3/31/01),[85] annual report, retail marketing software, and director's fees.

Taking into account the stipulations made by the parties, the reasonable costs that were uncontested, and the adjustments determined by the Commission, PacifiCorp's current test period revenue requirement of $788,670,000 is increased by $64,421,000. PacifiCorp's new retail revenue requirement is $853,091,000.

C. Future Property Sales

Staff proposed that the gains or losses from future property sales be placed in a balancing account for later refund or collection from consumers in a supplemental tariff. Staff believes that SB 1149 will effect PacifiCorp's decisions on property sales,

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[84] 1994 and 1995 expenses are substantially similar and approximate $1.5 million. The next four years are as follows:

1996	$2,187,000
1997	$3,799,000
1998	$3,970,000
1999	$6,870,000

[85] This adjustment is not included in the calculation of revenue requirement. Rather, these expenses will be recovered through a supplemental tariff.

and that it is difficult to predict the cost and amount of property PacifiCorp might sell. Further, because of SB 1149, it is not reasonable to rely on PacifiCorp's previous lack of sales to predict the company's future actions. Finally, Staff notes that PGE agreed to this treatment of future property sales in UE 115.

PacifiCorp claims that Staff's proposal is unnecessary. In looking at the three-year average of property sales (1998-2000), the average gain is approximately $36,000. Further, according to PacifiCorp, it is a misuse of the balancing account process to use it for routine issues. Future property sales are not an area where revenue or cost changes are volatile or significant. Finally, PacifiCorp is concerned about using this process for routine issues, particularly when the balancing account will likely have a one-sided effect, while ignoring future expense and rate base increases.

Commission Resolution

The future may show that PacifiCorp was correct in claiming that there is little reason to use a balancing account for the few transactions that may occur. However, in light of the effect that SB 1149 could have, and that it is not an overly burdensome process, we adopt Staff's proposal.

D. Rate Spread & Rate Design

Pursuant to the Regional Power Act, residential and small farm consumers of Pacific Northwest investor-owned utilities, such as PacifiCorp, have statutory rights to share in the benefits of low cost power sold by BPA. PacifiCorp and BPA recently entered into a contract that provides for federal system benefits to be provided in cash beginning October 1, 2001 through September 30, 2006. PacifiCorp proposes to provide these benefits in the form of a "cents per kWh" credit to qualifying customers. Although these benefits do not actually begin until October 1, 2001, PacifiCorp proposes to immediately apply these benefits to rates.

PacifiCorp proposes that no customer class receive a net rate increase of more than 15 percent. If the net rate increase is greater than 15 percent, PacifiCorp proposes to first apply any BPA benefit, and then proposes a rate mitigation adjustment (RMA) to reduce the rates to the 15 percent cap.

CUB argues that the rate spread should be developed prior to considering the effect of any BPA benefits. CUB is concerned that by applying BPA benefits first, eligible consumers could still get a 15 percent increase notwithstanding their BPA benefits. In essence, PacifiCorp would be using BPA credits as part of its RMA.

Staff supports CUB's position for allocating BPA benefits after the rate spread has been determined. However, during oral argument, Staff suggested a different approach for applying BPA benefits to residential customers. Staff recommended that the total dollars available to residential consumers be divided into two parts, with one part consisting of two-thirds of the monies, and the second part consisting of the remaining monies. The first part (two-thirds) should be used as credit for the kWh used by each residential consumer up to 500 kWh. The other part (one-third) should be used to calculate a per kWh credit for all usage above the 500 kWh level.

Staff supports this proposal because it believes that it is more equitable for all citizens to benefit from the BPA proceeds. This approach allows the benefits to be apportioned to some degree by customer rather than entirely by usage. This proposal also promotes a linkage between BPA power and PacifiCorp's residential consumers.

ICNU proposes an Alternative Rate Mitigation Adjustment (ARMA). This proposal includes:

1) limiting net price increases for each rate schedule to 1.5 times the overall net price change when prices are significantly less than cost of service and overall prices are being significantly increased, but not less than a 15 percent net price increase if justified by functionalized, unbundled cost of service results;

2) limiting price decreases to rate schedules when prices are greater than cost of service and overall prices are significantly increased; and

3) spreading any remaining amounts to be recovered, due to limiting price increases and limiting price decreases for particular rate schedules, to the remaining eligible schedules on a cents per kWh basis.

ICNU believes its proposal better serves the goals of SB 1149 by reducing the inflated subsidies provided to specific classes by PacifiCorp's RMA.

As for rate design, PacifiCorp proposes that the cost of service "Supply Service" option for residential customers consist of a three-block inverted energy rate. The first block is to be 500 kWh and below, the second block to be between 500 and 1,000 kWh, and the third block to be over 1,000 kWh.

In designing this rate, PacifiCorp targeted a difference of 45 percent to the Supply Service price (Schedule 200) between the first block and the third block. The second block equals the residential rate if a flat energy price were proposed for the class. The effect of combining the Schedule 4/Schedule 200 price is a 20 percent differential between the first and third blocks.

The parties support PacifiCorp's rate design proposal.

Commission Resolution

We adopt a variation of the proposals presented to us. First, we agree with CUB and Staff that the rate spread should be developed independently of any BPA benefits. To do otherwise gives rise to the charge that these credits are being used for non-qualifying consumers. We also agree that PacifiCorp should apply these benefits immediately to avoid multiple rate changes.

Next, we hold that the exchange benefits should flow through for non-residential small farm customers on a per kWh credit. This is consistent with how we have applied this benefit in the past. For residential consumers, however, we adopt Staff's recommendation of the two-third/one-third allocation. It makes sense to us to transition this benefit to a "per customer" basis from a usage basis. While acknowledging PacifiCorp's concern that this allocation may lead to additional customer confusion, we find that this process allows all customers to more appropriately share the BPA benefits.

Next, we adopt PacifiCorp's 15 percent net price increase as the threshold for a rate mitigation adjustment to be applied before the application of the BPA benefits. This Commission is authorized by statute to mitigate the rate impacts of moving to cost-based rates. We do not find that it is in the public interest to impose greater than 15 percent price increases. We further agree with PacifiCorp that the rate mitigation adjustment should not be subject to automatic adjustment. The Commission wants to be able to review whether the adjustment should be phased out, eliminated or increased, depending on the relevant circumstances.

Finally, we adopt the use of the inverted rate structure as proposed by PacifiCorp and accepted by the other parties.

IV. SB 1149 Issues

Since this case began, the Oregon legislature revised the timetable for implementing provisions of SB 1149 from October 1, 2001 to March 1, 2002. Although SB 1149 changes will not take effect until March 1, 2002, the parties felt that the Commission should issue its decision on SB 1149 contested issues as soon as possible rather than wait until closer to March 1, 2002.

The parties met in mid-July 2001 to discuss necessary changes to its current filings due to HB 3633. Based on their meetings, the following changes are made:

1) Various tariff schedules are changed consistent with the language set forth in a letter to all parties of record from PacifiCorp, dated July 19, 2001. These revisions, attached as Appendix F, are adopted by the Commission.

2) SB 1149-related tariff rules will reflect March 1, 2001 effective dates rather than October 1, 2001, except that Schedule 600 and related rules will reflect effective dates before March 1, 2001. PacifiCorp will work with the parties to determine the appropriate date for these rules.

3) DSM-related tariffs do not include termination dates and no changes are required.

Unbundling Revenue Requirement

Staff recommends postponing the unbundling of revenue requirement until after PacifiCorp's final revenue requirement is determined. Once the revenue requirement is set, Staff and PacifiCorp can work together to obtain the final unbundled requirement. Staff further recommends that the Commission direct the company to work with the parties to develop the final unbundled revenue requirement.

We find this recommendation reasonable. PacifiCorp is to work with the parties to develop the final unbundled revenue requirement.

SUPPLEMENTAL ORDER

Several issues, which have not been resolved by this order, are either related to SB 1149 or do not affect the setting of rates. These issues will be addressed in a supplemental order to be issued on or before October 1, 2001. These issues are:

Transmission proposals
Reclassification of Transmission Plant
ESS Service Agreement
Service Availability (Schedule 53)
Account Aggregation; Minimum Customer Size (Schedule 71)
Avoided Costs Data (Schedule 135)
Account Aggregation (Rule 8)
Facilities Charge (Rule 2 and Schedule 300)

CONCLUSIONS

1. PacifiCorp is a public utility subject to the Commission's jurisdiction.

2. The stipulations, attached as Appendices A, C, and D, should be adopted.

3. The stipulation, attached as Appendix B, should be adopted, except for the sections concerning portfolio ballot processing fees and standard service agreements. Those sections of the stipulation will be addressed in a supplemental order to be issued by October 1, 2001.

4. Based on the record in this case, the PacifiCorp rates that result from the stipulations adopted and the conclusions reached in the body of this order by the Commission are just and reasonable. A results of operations spreadsheet is attached as Appendix G.

ORDER

IT IS ORDERED that:

1. Advice No. 00-014 and Advice No. 00-015, filed by PacifiCorp on October 2, and November 1, 2000, respectively, are permanently suspended.

2. The stipulations attached as Appendices A, C, and D are adopted in their entirety.

3. The sections of the stipulation contained in attached Appendix B concerning portfolio ballot processing fees and standard service agreements are not adopted in this order, but will be addressed in the supplemental order to be issued consistent with our discussion above. The remainder of the stipulation is adopted.

4. PacifiCorp may file revised rate schedules consistent with the findings of fact and conclusions of law in this order, to be effective no earlier than September 10, 2001.

Made, entered, and effective ____________________________.

______________________________	______________________________
Roy Hemmingway	**Joan H. Smith**
Chairman	Commissioner

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