BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY Respondent. . . . . In the Matter of the Petition of PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY For an Order Approving Deferral of Costs Related to Declining Hydro Generation	DOCKET NOS. UE-050684/UE-050412

INITIAL BRIEF

ON BEHALF PUBLIC COUNSEL

FEBRUARY 27, 2006

I. INTRODUCTION AND SUMMARY OF POSITION

1. While PacifiCorp's filing has raised a wide range of complex issues, the appropriate resolution of the issues can be stated simply --- the Company has not carried its burden of proof to justify a rate increase, nor has it adequately justified its policy recommendations in other areas.

2. PacifiCorp has proposed a cost of capital recommendation that is excessive, measured on a stand-alone basis. There is extensive credible evidence that corroborates Public Counsel's recommended return on equity for PacifiCorp of 9.125%. In addition, evidence provided at the Commission's request shows clearly that the pending merger between PacifiCorp and Mid-American Holding Company (MEHC) will have a significant impact on the cost of capital. The Commission has requested and now has before it the record to take that into account in this case by means of a double leverage adjustment.

3. On the issue of revenue requirement, Public Counsel has identified a number of adjustments to the Company's case, that, taken together with the cost of capital recommendation, reduce the PacifiCorp revenue requirement by $25,564,000**.**

4. On the critical matter of multi-state allocation, this brief reviews the evidence which shows that the Company's proposed Revised Protocol methodology should be rejected because it allocates costs to Washington which are not based on power costs necessary to provide service to consumers in this state.

5. Public Counsel opposes the adoption of the power cost adjustment mechanism (PCA) recommended by PacifiCorp. The proposal is not consistent with the Commission's stated guidelines for PCAs. In addition, it is premature for a PCA to be put in place prior to resolution of the multi-state allocation issue.

6. The decoupling proposal presented by PacifiCorp and the Natural Resources Defense Council (NRDC) should not be approved. The proposal has little or no analytic support, it does not appear to be designed for Washington conditions, and includes no commitments for any particular investment in energy efficiency. Moreover, it poses the risk of windfall earnings gains for the Company at ratepayer expense.

7. Public Counsel and the other parties have reached agreement on rate spread and rate design issues, in the event that any rate changes are ordered in this docket.

II. CUSTOMER COMMENTS AND PARTICIPATION

A. The Yakima Public Hearing.

8. A public hearing was held in Yakima on December 1, 2005. In all, fourteen witnesses addressed the Commission at the Yakima hearing. Due to inclement weather, attendance was limited; the Commission later received letters from people who would have attended if not for hazardous driving conditions. Of those in attendance that did speak, none supported the rate increases proposed. Witnesses included senior citizens, community action agency staff, labor union representatives, small business owners, farmers and ranchers, and large business representatives.

9. John Tierney of Selah testified:

> This county does not have a robust economy. A lot of people are living at the poverty level or less. And any increase…will have an adverse effect not only on individual pocketbooks here in Yakima County and those people having to make choices between food or heat, but for each household that you take $180 a year out of, talking about a $15 a month increase, is $180 per household per year that you take out of the Yakima economy, and we cannot afford that...I don't feel I have an obligation, nor do I feel anybody in the state of Washington feels an obligation to pay for power transmission processes in the state of Utah…It should not be our responsibility. The rate increase that's being asked for, it's not fair, it's not just and it's certainly not reasonable. TR. 80:15-25, TR. 81:18-25.

10. Robert Ponti testified for the Northwest Community Action Center in Toppenish:

> …[T]he impacts of any rate increase tend to hit the poor population disproportionately…Winter months in the Yakima Valley are historically the months of unemployment or less employment for the folks involved in agriculture. And Yakima County has one of the higher unemployment rates in the state. We have entire school districts in the Yakima Valley that

> have the entire student population on reduced fee or free breakfast and lunch programs. TR. 65:4-7, 65:17-23.

11. Rhonda Worman, representing a local community action agency in Yakima that administers energy assistance programs, testified that by noon on the first day the agency had scheduled approximately 1500 appointments with clients seeking assistance with their heating bills. As of December 1, 2005, they had over 300 people on a waiting list and saw an additional 40 to 50 people a day walking in to their office seeking assistance. TR. 77:4-10, 77:24-78:2. Dale Kepley expressed concern for people like himself living on fixed incomes, particularly senior citizens dependent upon pension and Social Security benefits. TR. 74:5-11.

Ms. Louise Schneider of Selah testified:

> My husband and I own a ranch in the Wenas Valley raising hay and cattle. We irrigate approximately 225 acres of land using three pumps...It is a difficult even now with the present rates to farm and make a profit. If these increases are accepted, it will be next to impossible. We cannot increase our prices for hay and cattle. We can't just go and say we're arbitrarily going to raise our rates on cattle 20 percent or our hay 20 percent. There's absolutely no way we can pass on these proposed increases to our customers…I ask each of you members of the Washington Utilities and Transportation Commission to consider thoughtfully the full impact of these proposed rate increases. It gouges the residential customer as well as the farmer, who of necessity at this time farms with electric irrigation pumps. I ask you not to grant these increases. TR. 85:1-13, 86:12-21.

12. Doug Hester, process control and electrical superintendent at Boise Cascade's paper mill in Wallula, and Jim Jacobson, plant manager at Longview Fibre Company's mill in Yakima, both testified that the dramatic cost increases would be difficult to sustain in an industry that operates on thin profit margins and without much ability to pass costs along to customers. TR. 69:1-20, TR. 99:17-25. Robert Dawson, President of Local 69 of the Association of Western Pulp and Paper Workers Union, concurred with the statements regarding the paper industry, and added:

> Please make sure that the companies, Washington customers are not forced to pay for power that will be used to serve customers and possibly competitors in Utah. Wallula has done its part to control costs and energy consumption. We ask that you make sure that Pacific Power has done its part to control the cost too, before you approve any type of rate increase. TR.102:23-103:4.

B. Written Public Comments.

Public testimony Exh. No. 721 consists of letters, e-mails, and other written materials submitted by the public to provide comment on this case. The letters and other materials were submitted to the Commission and the office of Public Counsel. The exhibit includes a total of 45 written comments. Of these all oppose and/or express serious concern over the requested rate increase.

13. Elizabeth Dreher, of Yakima wrote:

> I am strongly opposed to the proposed increase of 17.9%. As an owner of GTO Car Wash in Yakima, WA we cannot continue to absorb these increases and will have no choice but to close our doors. We have been a solid business in Yakima for the past 15 years, but over the past couple of years our profits have been dwindling as our utilities have all increased…we can no longer make ends meet and are going deeper into debt…we have downsized our homes and taken a cut in pay. We are also driving older model cars and cutting costs wherever we can. We expect no less from all the entities who are raising their rates and only if it is absolutely necessary and fair.
> Exh. No. 721, p. 9 (letter received at WUTC November 10, 2005).

14. Robert E. Swope of Yakima wrote:

> I am astonished that the Pacific Power Company would have the audacity to suggest another rate increase for themselves.
>
> The cost of irrigating my 3.25 acres in Yakima during the month of August soared to $213 where as it was $166 the previous August and Pacific Power wants an 18 percent increase?
>
> Only last year Pacific Power was granted a rate increase of 7.5%. Let's contrast that with the pay raise the Washington Legislature granted teachers. After a number of years with no increase, teachers were given a 1.2% increase.
>
> I am a retired teacher. I have received no increase in my retirement from the state nor will I. My health insurance has risen to $409 per month and I must pay for it myself. My home as been reassessed upwards another $8,600. The West Valley

> School System wants to pass another bond issue and add more to my property taxes. I will have to vote no.
>
> Please, let's draw the line with Pacific Power. They have received increases which have been more than generous.
>
> Please, no more!

Exh. No. 721 (letter received at WUTC November 15, 2005).

III. APPLICABLE LAW

15. The "ultimate determination" which must be made by the Commission in a rate proceeding is "whether the rates and charges proposed in the revised tariffs are fair, just, reasonable and sufficient, pursuant to RCW 80.28.020." *WUTC v. Avista* Corporation, Docket Nos. UE-991606, UG-991607, Third Supplemental Order (September 2000), ¶ 14. The Commission elaborated:

> These questions are resolved by determining the Washington intrastate adjusted results of operations during the test year, establishing the fair value of the Company's property-in-service for intrastate service in the state of Washington (rate base), determining the proper rate of return permitted the Company on that property, and then ascertaining the appropriate spread of rates charged various customers to recover that return.

Id., ¶ 14.

The Commission went on to explain in more detail the analysis required in the setting of fair rates:

> In order to accomplish these tasks, the *parties in a rate proceeding develop evidence* from which the Commission may determine the following:
>
> 1) The appropriate *test period* ….The test period is used for investigation of the Company's operations for purposes of the proceeding;
>
> 2) The Company's *results of operations* for the appropriate period, adjusting for unusual events during the test period, and for known and measurable events;
>
> 3) The appropriate *rate base*, which is derived from the balance sheets of the test period. The rate base represents the net book value of assets provided by investor's funds which are used and useful in providing utility service to the public;

4) The appropriate *rate of return* the Company is authorized to earn on the rate base established by the Commission;

5) Any existing *revenue excess or deficiency*; and

6) The *allocation* of the rate increase or decrease, if any, fairly and equitably among the Company's rate payers.

Id., ¶¶ 15-21. (emphasis added). The burden of proof is on PacifiCorp to establish that the proposed rates which would result from the settlement are fair, just, reasonable, and sufficient. RCW 80.04.230(2).

16. As a general matter, the Commission must regulate in the public interest. RCW 80.01.040(3). Both the contested rate determinations, and approvals of agreed matters in this docket must be based upon a determination that the result is in the public interest. *Id.*, ¶ 449 (contested rates); *WUTC v. Avista Corporation,* Docket No. UE-011595, Fifth Supplemental Order (June 18, 2002)(2001 electric rate case all-party settlement approval).

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

A. Public Counsel's Recommended 9.125% Return on Equity Meets All Regulatory Tests Of A Fair Return.

17. A public utility with facilities and assets used and useful in public service is entitled to no more than a reasonable opportunity to earn a fair rate of return on its investment. The United States Supreme Court established the standard with which to evaluate whether a rate of return is fair in *Bluefield Waterworks & Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*), stating:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management . . .to raise the money necessary for the proper discharge of public duties.

Bluefield, 262 U.S. at 693.

Twenty-one years later, the Court reviewed the issue of fair rate of return in *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*). In *Hope*, the Court held that a fair rate of return "should be commensurate with returns on investments in other enterprises having corresponding risks" while being sufficient "to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital." *Hope*, 320 U.S. at 603. The Court noted that "[t]he rate-making process under the Act, *i.e.*, the fixing of 'just and reasonable' rates, involves a balancing of the investor and consumer interests . . . and does not insure that the business shall produce revenues." *Id.* More recently, the Court stated that consumers are obliged to rely upon regulatory commissions to protect them from excessive rates and charges. *See Permian Basin Area Rate Cases*, 390 U.S. 747, 794-95 (1968) (*citing Atlantic Refining Co. v. Public Service Comm'n*, 360 U.S. 378, 388 (1959)).

18. The Public Counsel's recommended return on common equity capital of 9.125% fulfills all of the legal requirements set out in the cases cited above. The 9.125% return on equity works to assure the financial soundness of PacifiCorp and provides a return commensurate with returns of similar-risk firms, which will allow the Company to continue to be able to attract the capital necessary to fulfill its customer service obligations.

19. 1) <u>Assure financial soundness</u>: As noted in Exh. No. 91-T, p. 4, a 9.125% equity return, operating through a recent average actual capital structure for PacifiCorp provides the Company an opportunity to achieve a pre-tax interest coverage of 2.83 times. That interest coverage level is greater than the interest coverage actually earned by PacifiCorp over the last three years (2.20 times). Also, the Company has provided evidence that the Public Counsel's recommendation in this proceeding (whether on a stand-alone basis for PacifiCorp, or through a double-leverage

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adjustment) allows the Company to achieve bond rating benchmarks that exceed past averages:

S&P Finan. Benchmarks	PacifiCorp Historical Financial Benchmarks 3/31/01	3/31/02	3/31/03	3/31/04	3/31/05	9/30/05	AG Recom. ROR PCorp Only	AG Recom. ROR with Double Lvg.
FFO/Interest	2.5x	3.0x	3.5x	3.7x	3.4x	3.3x	3.9x	3.9x
FFO/Debt	9.50%	12.10%	16.60%	18.40%	17.30%	16.50%	19.70%	19.60%
Debt/Capital	55.40%	62.40%	58.50%	57.60%	59.60%	57.90%	58.20%	58.20%

Data from Exh. No. 29, 66-T and 74

20. 2) Attract Capital: A 9.125% return on common equity for PacifiCorp is similar to returns investors require from similar-risk firms and is supported by substantial evidence provided by all parties in this proceeding. Because that 9.125% return on equity is similar to the returns investors require for other similar-risk firms, it will ensure that the Company will continue to be able to attract capital, as required by the regulatory guidelines set out by the Court. The evidence supporting the efficacy of a 9.125% equity return in the record in this case is substantial:

- DCF Evidence – The Discounted Cash Flow (DCF) method is, by far, the most widely used econometric methodology used to estimate equity returns in regulated rate proceedings. TR.1194. The DCF provides the most reliable estimate of the cost of equity capital and is the equity cost estimation method on which this Commission has long relied. Exh. No. 91-T, p. 51. All of the witnesses in this proceeding—working independently—have presented DCF evidence that indicates the 9.125% equity return recommendation of the Public Counsel is reasonable.

DCF ESTIMATES BY EXPERTS IN THIS PROCEEDING			
Hill Ex. 102	Rothchild Ex. 158	Hadaway Ex. 35	Gorman Ex. 129
9.23%	8.66%	9.30%	8.90%

- Corroborative Evidence of Other Econometric Models – Public Counsel witness Hill's corroborative models support his DCF estimate and indicate a reasonable range of equity capital costs for similar-risk companies ranging from 8.55% to 9.28%.[1] Dr. Rothchild produced Risk Premium/CAPM equity cost estimates ranging from 7.66% to 9.55%. Mr. Gorman's risk premium estimate, averaged 9.9%, but is based on projected rather than current bond yields, and, therefore, is somewhat overstated. Exh. No. 91-T, p. 24.
- Investor Return Publications - Investor services are advising their subscribers to expect returns from similar-risk investments that average 8.4%—below the Public Counsel recommended equity return of 9.125%. Exh. No. 91-T, p. 17.
- Observable Capital Costs are Historically Low –The capital cost rates associated with bonds (bond yields) are directly observable. Those data indicate that capital costs are currently at their lowest level in more that 40 years. Exh. No. 96. Also, even though short-term rates have increased over the past year due to monetary tightening at the Federal Reserve long-term interest rates have not increased and, in fact, have declined. Exh. No. 91-T, p. 16.

[1] Mr. Hill's recommended range of equity capital costs from 8.75% to 9.50% is conservative (i.e., on the high side).

ATTORNEY GENERAL OF WASHINGTON
Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012

- Lower Risk Premiums – New research in the field of financial economics indicates that the return premium required by equity investors over bond returns is substantially lower than is indicated by historical averages. New research by prominent economists indicates the risk premium required by equity investors in the future is much lower—3% to 4.5%. With current T-bonds yielding approximately 5%, a risk premium of 3% to 4.5% implies investor required equity returns of 8% to 9.5% for the market, generally. An equity return for lower-risk utility assets of 9.125% is generous by that standard.

B. PacifiCorp Witness Hadaway's Equity Cost Estimates Above 10% Are Not Credible.

21. Cost of capital testimony is opinion testimony. The expert's opinions are based on financial theories and econometric models that are well accepted and long-established. However, when the expert changes methodologies in order to affect the outcome of the estimate, the reliability of those estimates is diminished, especially when those methodologies change from case-to-case. Dr. Hadaway's alternative DCF and Risk Premium cost of equity estimates that produce results above 10% are not credible because he has changed his methodologies in order to affect the outcome— to produce higher results. The substantial differences between Dr. Hadaway's testimony on behalf of PacifiCorp in this jurisdiction two years ago in *WUTC v. PacifiCorp,* Docket No. UE-032065, Sixth Supplemental Order and his testimony in the instant proceeding are set out below.

- Dr. Hadaway elects to ignore the results of his standard DCF in this proceeding, because the cost estimate is too low. Exh. No. 21-T, p. 24. He did not do so in his testimony two years ago. Exh. No. 46.
- Dr. Hadaway did not include a "market-based" DCF analysis in this proceeding, but did so in his testimony two years ago. Exh. No. 49. That

methodology applied to this case produces a DCF estimate of 7.1%. Exh. No. 50.

- Dr. Hadaway includes a DCF equity cost estimate in his testimony in this proceeding in which the growth rate is based solely on long-term Gross Domestic Product growth. It produces his highest DCF result. He did not include that analysis in his testimony two years ago. TR. 2102.
- In determining his long-term GDP growth rate, Dr. Hadaway elected to include more data in his historical average in this proceeding that he did in the same calculation two years ago. Because GDP growth has been trending downward, the result of using more historical data is to increase the GDP growth rate. In this case, Dr. Hadaway uses a long-term GDP rate of 6.6%. Two years ago he used 6.0%. TR. 1203, 1204, 1206.
- In his Risk Premium analysis in this proceeding, Dr. Hadaway elected to use projected bond yields. In his Risk Premium testimony two years ago, he used current yields. The use of projected bond yields instead of current yields increases the Risk Premium results by almost 100 basis points. TR. 1222, 1224-5.

22. Two other points regarding Dr. Hadaway's testimony deserve mention. First, Dr. Hadaway elects to ignore his standard DCF methodology and change his other DCF methods (drop the market price method and substitute the GDP-growth-only method) because he believes analysts' published growth estimates are "pessimistic." Exh. No. 21-T, p. 24; Exh. No. 49; TR. 1197-8. Published analysts' growth rates are used in cost of capital estimation as surrogates for investor-expected growth of the DCF because they are widely available and represent objective information in the marketplace that will determine investor expectations. Exh. No. 91-T, pp. 44-48. PacifiCorp witness Hadaway used those published analysts' growth rate estimates to estimate the cost of equity capital with a DCF model in PacifiCorp's last rate proceeding. If analysts' growth rate estimates were investor-influencing in the last rate case, there is no reason to believe that analysts' growth rate projections are not currently reflected in utility market prices. Dr. Hadaway certainly has not offered a credible reason why they are not. Since the cost of capital environment is currently low, it is reasonable that growth rate projections are lower than they have been. However, and most importantly, it is not reasonable for Dr. Hadaway to ignore the DCF results produced through the use of analysts' growth rates and to substitute other growth rates just to produce a higher result.

23. Second, the growth rate Dr. Hadaway substituted for analysts' growth rate projections was an historical average of Gross Domestic Product (GDP) growth. Exh. No. 49. In order for GDP to be a rational and reliable proxy for long-term electric utility growth rates, there must be a showing that there is a close relationship between GDP growth and electric utility growth. Dr. Hadaway has made no such showing, neither in his Direct testimony nor in his rebuttal when he had the opportunity to respond to Public Counsel witness Hill's identification of the flawed reliance on GDP growth. Exh. No. 91-T, pp. 57-59. Similarly, in cross-examination, Dr. Hadaway never provided any tangible evidence that GDP growth is related in any way to investor-expected electric utility growth rates. TR. 1208-1210. If there were a relationship, it would be simple enough to show the average historical growth in utility earnings or dividends and compare that to average historical GDP growth. Dr. Hadaway never did that and his cost of equity testimony based on the GDP growth is not reliable because of that fact.

C. PacifiCorp Stand-Alone Capital Structure.

24. The Company's requested ratemaking capital structure contains substantially more common equity capital as a percentage of total capital than that with which the Company has actually been capitalized recently. The Company requests that rates be set using a capital structure consisting of 49.40% common equity, 1.10% preferred stock and 49.50% long-term debt. Exh. No. 91-T, p. 34. That capital structure excludes the least expensive form of capital—short term debt.

25. Including a recent average level of short-term debt would bring the Company's requested ratemaking equity ratio to 47.85% of total capital. Exh. No. 91-T, p. 34. However, even that level of common equity substantially overstates the common equity ratio with which PacifiCorp has capitalized its utility operations recently. Over the most recent five quarters, PacifiCorp's actual common equity ratio has averaged 43% to 45% of total capital. Exh. No. 97, p. 1.

26. Even though the Company's parent (Scottish Power) has committed to add common equity to the capital structure of PacifiCorp, that does not mean that equity infusion should be included in rates in this proceeding. The Company may add debt at an equivalent rate, maintaining the current capital structure ratios, as occurred in the quarter ending June 30, 2005. Exh. No. 91-T, pp. 35-36. Also, this Company, in its most recent rate case before this Commission, based its rates on a 47% projected common equity ratio. As shown in Exh. No. 97, following the rate case, the Company never achieved an equity ratio close to its projected level.

27. In addition, the Company never established any clear need for a substantial increase in common equity ratio based on increases in risk. There is no discussion in the Company's testimony regarding any substantial increase in purchased power obligation, a change in the nature of the Company's power supply portfolio, its customer base, operational profile or other factors that would impart significantly greater operational risk. The current capital structure has been sufficient to support the Company's A-/BBB+ bond rating in the past and the Company has provided no reason to believe that it would not continue to do so in the future.

28. Third, an increase in common equity ratio to the level requested by the Company would be unnecessarily expensive for Washington ratepayers, costing nearly $4.6 Million annually. Exh. No. 97, p. 2.

29. Fourth, the Company's use of short-term debt has been significant and consistent. Exh. No. 97, p. 4.

30. Fifth, the requested 49% equity ratio ratemaking capital structure is substantially in excess of the average common equity ratios in the electric utility industry. Exh. No. 97, p. 3.

Based on the Company's own operational and financial history, a reasonable ratemaking capital structure consists of 44.0% common equity, 1.0% preferred stock, 52.0% long-term debt and 3.0% short-term debt. Exh. 97, p. 5.

D. Double Leverage Adjustment.

31. The following facts are not in dispute:

- PacifiCorp's recent average stand-alone capital structure consists of approximately 44% common equity and 56% fixed-income capital (preferred stock, long- and short-term debt). Exh. No. 97, p. 1.
- Scottish Power's current consolidated capital structure consists of approximately 54% common equity and 46% fixed-income capital. Exh. No. 114, p. 5.
- Mid American Energy Holding Company (MEHC) has a consolidated capital structure of approximately 20% common equity and 80% fixed-income capital. Exh. No. 114, p. 5.

Double leverage exists in a holding company/subsidiary relationship when the consolidated parent company finances its equity investment in the subsidiary with a mix of debt and equity, rather than just equity capital. Double leverage does not exist with PacifiCorp's current ownership because Scottish Power has a consolidated common equity ratio that is higher than that of PacifiCorp, the equity returns awarded PacifiCorp will flow to a parent equity base that is a larger proportion of total capital than that employed by PacifiCorp, and the return to the parent will not be "levered" through the use of debt at the parent level. The situation is different if the merger with MEHC is allowed to proceed. MEHC has substantially more debt at the parent level than PacifiCorp has on a stand-alone basis. Therefore, the equity returns allowed PacifiCorp by this Commission will be levered through that ownership arrangement and MEHC will earn a return substantially in excess of that appropriate for an electric utility operation with that level of financial risk. Exh. No. 114, pp. 5-7.

32. The Company witnesses do not appear to disagree that double leverage exists with an MEHC/PacifiCorp relationship (Exh. No. 811-T, p. 2), they just do not believe that the Commission should make any sort of adjustment to account for additional leverage at the parent company level.

33. The Company's primary argument against a regulatory double-leverage adjustment is that such adjustments assume the parent and subsidiary's capital costs to be the same and do not recognize the increased capital costs of the parent arising from increased risk. Exh. No. 811-T, p. 9. Unfortunately for the Company, that argument does not apply to either Staff's or Public Counsel's recommendations in this case. Both Staff and Public Counsel recognize the additional risk of the parent due to additional leverage and attribute appropriately higher capital costs. Public Counsel witness Hill provides an analysis that indicates a reasonable increment to the 9.125% common equity cost rate (which is appropriate for PacifiCorp on a stand-alone basis) would be 100 basis points (1%) for the new parent company, MEHC. Mr. Hill also utilized MEHC's actual debt cost rate, which (due to a very high preferred trust series held by Berkshire Hathaway) is higher than PacifiCorp's debt cost. Exh. No. 114, p. 18, f. 7.

34. In sum, both the Staff and Public Counsel have recognized that investors who leverage their investments (such as an investor that buys on margin or a holding company that buys a utility with a mix of debt and equity) raise their financial risk and their required return. The Company's complaints (and their reference in the cross-examination of Mr. Hill to the Morin text) are misplaced when they argue that "double leverage devotees" do not recognize that differences in financial risk call for difference in capital costs. On the contrary, as discussed above, Mr. Hill recognizes and takes this into account in his testimony. TR. 1724—25.

35. Properly adjusting PacifiCorp's capital structure and capital costs to recognize that, following the merger, the Company's equity will be owned by MECH and financed with about 30% common equity and 70% debt, the overall cost of capital for PacifiCorp should be 7.45%. Exh. No. 116. As noted in Exh. No. 107, on a stand-alone basis, PacifiCorp's overall cost of capital would be 7.52%. Because the new parent company, MEHC, intends to finance its investment in PacifiCorp with substantial amounts of debt, the return allowed PacifiCorp must be lowered in order that the parent/subsidiary financial structure (which is determined at the parent level) not result in the parent over-recovering its cost of equity capital. This adjustment passes on to ratepayers the benefits of the additional debt leverage used by the parent company to purchase the utility and, in so doing, balances the interests of ratepayers and the Company's new investors.

E. Additional Issues.

36. The Company takes the position that a double leverage adjustment is not necessary due to the ring-fencing measures that MEHC has agreed to put in place with the merger. Exh. No. 811-T, p. 14, 15. This is incorrect. Public Counsel witness Hill points out that ring-fencing is an arrangement designed to prevent the parent company from "raiding" the utility's assets in the event of a financial melt-down at the parent company level. A double leverage adjustment, on the other hand, is a rate-making mechanism that prevents the parent from over-earning its cost of equity capital. They are two different mechanism designed for two different and distinct purposes. The existence of one (ring-fencing) does not negate the need for the other (a double-leverage ratemaking adjustment). Exh. No.114-T, p. 15.

37. The Company also takes the position that if double-leverage is considered, then the acquisition adjustment (the amount of the purchase price over the depreciated original cost of the plant) should be included in PacifiCorp's rate base. TR. 1648. However, Washington is not a "fair value" regulatory jurisdiction; rather, it is one in which utility rates are based on the depreciated original cost of the used and useful utility plant. Allowing a return on the market price of utility assets would violate that long-standing regulatory paradigm. As Public Counsel witness Hill put it, setting rates on the market price of PacifiCorp's assets would turn "cost-based ratemaking into 'deal-based' ratemaking." Exh. No. 114, p. 16. Also, the Company's position that the consideration of additional debt at the parent level calls for consideration of the acquisition premium for inclusion in rate base incorrectly attributes the financing of PacifiCorp solely to debt. However, the acquisition premium will not be financed entirely with debt and there is no nexus between a ratemaking adjustment for double leverage and the consideration of any portion of the acquisition adjustment in rate base. Exh. No.114, p. 17.

38. Finally, during cross-examination by PacifiCorp of Staff witness Elgin, the Company presented Mr. Elgin with several parent/subsidiary financial structures and attempted to show that MEHC would earn a lower return than that allowed PacifiCorp. Those examples where double leverage exists are all flawed by the inclusion of an acquisition premium in the determination of the rate of return earned by the parent, as Mr. Elgin recognized when discussing Exh. No. 810-B. TR. 1530. Regarding page 3 of Exh. No. 810-B, the Company depicts a "Levered" Structure and shows the parent (AquireCo) earning a 6.1% return on equity when the regulated subsidiary is allowed and earns a 10% return on equity. However, only $500,000 of parent equity and $500,000 of parent debt is supporting the purchase of the $1,000,000 of subsidiary equity. The Company's example has $2,000,000 of parent capital purchasing $1,000,000 of subsidiary equity (and therefore injects the acquisition premium into the calculation of return). Correcting the Company's Exh. No. 810-B example to eliminate the unnecessary inclusion of the acquisition premium: 1) the subsidiary earns 10% on its $1,000,000 of equity capital and sends $100,000 to AcquireCo; 2) AcquireCo pays interest on the $500,000 of debt supporting its equity investment in the subsidiary, which is $19,500 net of tax; 3) the remaining $80,500 is applied to the $500,000 of AcquireCo equity actually supporting its investment in the subsidiary's equity capital and the return earned by AcquireCo is 16.1% [$80,500÷$500,000]. The additional leverage at the parent company level, absent a regulatory adjustment at the utility subsidiary, will allow the parent to earn a return that is in excess of its cost of capital and is unfair to ratepayers.

V. REVENUE REQUIREMENT

A. Overview.

Public Counsel has identified a number of issues where downward revenue requirement adjustments should be made in the Company's case. These are summarized here and presented in the testimony of David Effron. The overall effect of Mr. Effron's recommendations is a reduction in revenue requirement of $25,564,000. Exh. No. 293, p. 2, column 1. This includes the effect of Steve Hill's cost of capital recommendation in direct testimony. Public Counsel has not presented a comprehensive review of all revenue requirement issues, but does not take issue with adjustments presented by Staff or ICNU.

B. Deferred Debits.

39. The deferred debits represent costs that the Company, without Commission authorization, deferred on its books of account. Exh. No. 291, pp. 3-6 (Effron). The amount remaining in dispute on this adjustment is not large. However, acceptance of the Company's position would establish a bad precedent. The Company has not provided any substantive reason why it should be able to include the disputed deferred debits in rate base.

40. In his rebuttal testimony, Mr. Wrigley appears to take the position that no explicit authorization by the Commission is necessary to defer costs for future recovery. Exh. No. 195, pp. 16-17, (Wrigley). On page 17, he refers to a response to a Staff Data Request as support for the inclusion of the deferred debits in rate base. Note that the paragraph from the Uniform System of Accounts (FERC Account 186) that he quotes on page 17 pertains to the *book* accounting for the deferred debits, not to the ratemaking treatment. Exh. No. 210.

41. It seems to be Mr. Wrigley's position that if the Company, at its own discretion, elects to defer certain expenditures on its books of account, then this treatment binds the Commission's future ratemaking treatment of the deferrals. He does not offer any explanation of why the Company should be authorized to include the deferred debits in rate base, even though their inclusion has been directly challenged in this case. What remains is an argument that the

Commission must let the Company include the deferred debits in rate base for no other reason than that the Company, at its own discretion, elected to defer these costs on its books of account. This should not be acceptable to the Commission.

C. Electric Plant Acquisition Adjustments.

42. The acquisition premium represents the price paid to other utilities for certain assets in excess of their net book value at the time of the acquisition. Because fixed assets in rate base are, as a general rule, included at original cost when first dedicated to public service, the acquisition premium should not be included in rate base, unless the utility can demonstrate that the acquisition of the assets, even at a price above the net book value on the books of the selling utility, is in the best interests of ratepayers. The Company has made no such demonstration. Exh. No. 291, pp. 6-9 (Effron). While Company witness Wrigley cites the approval of account treatment and a prudence report on the Yampa acquisition adjustment, he cites no Commission order approving ratemaking treatment for the acquisition adjustment. Exh. No. 195, p. 17, ll.18-19 (Wrigley). Likewise, at page 18 of his rebuttal, he refers to two acquisition adjustments, but provides no supporting justification for including the premium in rate base. The Company has failed to carry its burden. The effect of eliminating these items from rate base and operating expense is a reduction in revenue requirement of $1.5 million. Exh. No. 291, p. 9, l. 2 (Effron).

D. Pro Forma Plant Additions.

43. This Company adjustment purports to represent what are described as major plant additions forecasted to occur after the end of the test year, i.e., through March 31, 2006. The adjustment increases the Washington jurisdictional plant in service by $39.2 million on a pro forma basis. Exh. No. 291, p. 9, ll. 4-18 (Effron). At a minimum, two modifications should be made to this adjustment. First, it should be modified to reflect more recent data. Second, if plant is adjusted through March 2006, it is reasonable to adjust the depreciation reserve to the same date. *Id.*, pp. 11-12. The effect of these adjustments is to reduce the revenue requirement by $4.4 million. *Id.*, p. 12, l. 23.

44. In his rebuttal testimony, Mr. Wrigley offered no response to the first point. With regard to the second issue, he concludes that the depreciation reserve adjustment is, in effect, subsumed by the Company's acceptance of Staff's production factor adjustment. Exh. No. 195, pp. 15-16, (Wrigley). He offers no evidence to support this conclusion. The Staff method accepted by the Company relates to the allocation of production plant to the Washington jurisdiction. Mr. Wrigley has not established that the method achieves a proper matching between the production plant in service include in rate base and the related depreciation reserve.

E. Out of Period Revenue Expense.

45. The Company has not been able to identify or describe the factors that lead to its out of period corrections which result in a decrease of $1.4 million in test year revenues. Given the atypical magnitude of the adjustment, it has not been adequately supported by the Company. The adjustment should be eliminated and pro forma revenues increased accordingly. Exh. No. 291, pp. 13-14 (Effron).

F. Capital Stock Expense.

46. PacifiCorp takes the position that the Company should be able to recover the costs of issuing common stock as an operating expense. Exh. No. 195, pp. 21-23 (Wrigley). On page 22, he refers to the treatment of capital stock expenses in FERC Account 214. Exh. No. 209. However, these costs are not operating expenses. Capital stock expense is not treated as an operating expense in the uniform system of accounts. Exh. No. 209; Exh. No. 291, pp.14-16 (Effron). Rather, the capital stock expense is treated as an offset to the net proceeds from issuing common stock.

47. The PacifiCorp response to Staff Data Request No. 70 is the prospectus supplement from the last issuance of common stock. Exh. No. 211. These are the issuance costs that the Company is seeking to recover. The second page of Exh. No. 211 shows the issuance price and the underwriting fees. The price to the public is $20.875 per share. The date of the prospectus supplement is March 15, 1996. Page S-3 has relevant financial data. On December 31, 1995,

there were 284.3 million shares outstanding and total common equity of $3.633 billion. This equates to a book value of $12.78 per share. Thus, even after deducting all the capital stock expenses, the net proceeds per share to the Company were still well in excess of the net book value per share.

48. Even after the capital stock expenses, the issuance of common equity did not result in any dilution of the net book value of the shareholders' investment. On the contrary, the issuance increased the book value per share, even after the issuance costs. Note that the Company is better off than if it issued stock at say $18 per share – which would still be accretive to the book value per share – with no issuance costs. In short, there is really nothing that has to be recovered.

49. If the Commission determines that the Company should be granted an allowance for the recovery of stock issuance expenses, it should be through a flotation allowance included in the authorized return on equity. Exh. No. 291, p. 15, ll. 17-22 (Effron).

50. Elimination of the amortization of capital stock expenses reduces pro forma test year operating expenses by $171,000 and the Company's revenue requirement by $179,000. Exh. No. 291, p. 16, l. 2 (Effron).

G. Incentive Compensation.

51. Incentive compensation based on the achievement of financial goals benefits shareholders, not ratepayers, and such should not be included in the Company's revenue requirement. As the Company has not provided an analysis of the incentive compensation based on financial goals, we are recommending the exclusion of 50% of the incentive compensation from the cost of service. Exh. No. 291, pp. 16-17 (Effron).

52. Company witness Wilson claims to "show that the Company's incentive pay programs are 90 percent performance-based, in response to Mr. Effron's argument that half of the basis for incentive pay is financial and should be excluded." Exh. No. 271, p.2, ll. 9-11 (Wilson). The Company has not provided an actual analysis of the incentive compensation, however, showing how much is financial and how much is "performance-based." For example, note that on Exh. No. 272, which accompanies Wilson's rebuttal testimony, it is not possible to determine how much of the actual incentive payout relates to the various goals that he describes. The Company has not established that 50% is an unreasonable estimate of the incentive compensation based on financial goals. Thus $936,000 is a reasonable estimate of the incentive compensation that should be excluded from the cost of service. Exh. No. 291, p. 17, l. 19 (Effron).

H. IRS Tax Settlement.

53. In previous years, PacifiCorp made settlement payments of approximately $64.2 million (total Company) to settle the treatment of certain disputed tax issues from the 1990s. Of that amount, $3,876,000 (net of timing differences on which deferred taxes were recorded) was allocated to Washington. The Company is proposing to amortize that amount over five years and include 50% of the unamortized balance, or $1,551,000, in rate base and 50% of the annual amortization, or $388,000, in pro forma test year federal income tax expense. *See generally*, Exh. No. 291, pp. 18-19 (Effron).

54. The Company has not established that the settlement payments relate to any income tax deductions (or other disputed income tax items) that were flowed through to the benefit of Washington ratepayers. If the Company could establish that (1) it took an income tax deduction in a given year and that tax deduction was reflected in the determination of the total income tax expense included in its cost of service as a reduction to its income tax expense; and (2) the particular income tax deduction was subsequently challenged by the IRS and ultimately resulted in additional income tax payments being made by the Company; then the Company would at least have established some justification for recovering the settlement payments in its revenue requirement. However, the Company has not made any attempt to establish that the settlement payments related to tax deductions which inured to the benefit of ratepayers. If the settlement payments related to tax deductions that were never of any benefit to ratepayers in the first place, then the Company has no legitimate claim to recover those settlement payments from ratepayers.

55. Company witness Martin, in his rebuttal testimony, cites the settlement in the last PacifiCorp rate case as authorization for recovery of the tax settlement payments. Exh. No. 181, p. 17, ll. 19-21 (Martin). The settlement in the last case was just that – a settlement in that particular case. The language of the settlement makes it clear that the resolution of issues for the purpose of settlement was not to be precedent for future cases. *WUTC v. PacifiCorp,* UE-032065, Sixth Supplemental Order, Appendix A (Settlement Agreement), p. 10.

56. Mr. Martin also states that "[t]he tax settlement payments for which the Company is seeking recovery in this case relate to the exam and appeal of the 1991-93 returns and the exams of the 1994-98 and 1999-2000 returns." The last rate case prior to those years was 1984. There is no possible way to relate the disallowed deductions in the 1990s to tax deductions reflected in the cost of service in 1984. Nor did the Company make any attempt to do so. Exh. No. 181, p. 20, ll. 9-11 (Martin).

57. Mr. Martin also claims that "the correct basis for allowing this adjustment is that it has never been included in the estimate of taxes included in rates." *Id*. p. 25. Using this as the standard would allow the tax effect of matters having nothing to do with the cost of service into the Company's revenue requirement. This is *exactly* what is wrong with the Company's position.

58. Martin goes on to assert that he could show that the tax payments in question meet the two criteria cited above. *Id***.,** p. 26, ll.1-3. However, he does not actually present anything showing either the disallowed deductions to which the tax payments relate or how the disallowed deductions meet the criteria. In summary, the Company has not presented any evidence as to why any part of the settlement payments to the IRS should be recovered from ratepayers.

59. The effect of eliminating this adjustment is a reduction in revenue requirement of $852,000. Exh. No. 291, p. 19, l. 20 (Effron).

I. Income Tax Calculation.

60. Public Counsel witness David Effron discusses this issue at Exh. No. 291, pp. 19-21. The total effect of this adjustment is a reduction in revenue requirement of $739,000. *Id.,* p. 21, l. 8.

1. Interest & Dividends (AFUDC Equity).

61. The Company agrees that this item should have no effect on Washington taxable income and should be removed from book income to arrive at taxable income. Exh. No. 195, p. 20 (Wrigley). However, as presented by the Company, this item has the effect of increasing taxable income by reducing the available income tax deductions. To achieve the intended effect, this item should be eliminated.

62. Mr. Wrigley describes the Company's method of calculating income tax expense on pages 20-21 of his rebuttal testimony, Exh. No. 195. On page 20, he addresses the "Interests & Dividends AFUDC-Equity" issue. He states that "the amount of $611,689 shown as part of the current state and federal income tax calculation section of the results shown on Line 1375 on Page 2.22 of Tab 2 in Exhibit No.___(PMW-3) is accompanied by a Schedule M deduction of $679,000 (shown on page 3 of Tab B6 of the same Exhibit)."

63. The $679,000 Schedule M deduction to which he refers is included in the "temporary" Schedule M deductions. The Company records deferred income taxes on the "temporary" Schedule M deductions. Thus, the deferred tax expense offsets the reduction to current income taxes resulting from this "Schedule M deduction."

64. Contrary to Wrigley's rebuttal, the Company's treatment of "Interests & Dividends AFUDC-Equity" does result in an increase to the income tax expense included in the cost of service. The income tax expense must be adjusted to reflect the elimination of this item.

2. State and federal income tax calculation.

As part of this income tax adjustment, Mr. Effron also takes issue with the Company's calculation of state and federal tax amounts. Exh. No. 291, pp. 23-24[2].

VI. MULTI-STATE COST ALLOCATION ISSUES

A. Overview.

65. One of the most important issues in this case is how best to fairly and accurately determine the Washington State share of PacifiCorp's multi-state costs. PacifiCorp presents the Revised Protocol methodology as the answer to this question. Public Counsel does not agree. As discussed in more depth in this section, Revised Protocol is not consistent with the policy goals announced at the time of the Utah Power/Pacific Power & Light merger. It does not allocate costs on a "cost causative" basis. The Revised Protocol methodology contains a number of flaws, as outlined in the testimony of Public Counsel witnesses Merton Lott and Charles Black and discussed below. Significantly among these, it does not properly account for the differing impacts of growth in different parts of PacifiCorp's territory. Public Counsel, therefore, opposes the adoption of Revised Protocol by this Commission, and recommends that the Commission direct the parties to develop an alternative portfolio approach in the manner outlined in Public Counsel's testimony.

B. The Utah/PacifiCorp Merger and Subsequent History of Allocation.

1. The merger.

66. The appropriate starting point for addressing the allocation issue is the Utah/Pacific merger, approved by the Washington Commission in July 1988.[3] A review of the merger and

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[2] This portion of the adjustment was derived using numbers in PacifiCorp direct testimony, Exh. No.193. These numbers changed in rebuttal, Exh. No. 198. The change is not reflected in Mr. Effron's testimony but has a minor impact only on the final number.

[3] *In the Matter of the Application of PacifiCorp (Maine) to Merge with PC/UP&L Merging Corp. (PacifiCorp Oregon) and to Issue Such Securities As May Be Necessary to Effect A Merger With Utah Power & Light Company*, Docket No. U-87-1388-AT, Second Supplemental Order Approving Merger With Requirements (Utah/PacifiCorp merger, merger, or Second Supplemental Order).

subsequent history of the allocation issue is relevant to this case because it provides essential factual context, and establishes a framework of fundamental principles for allocation. Both the issues raised by the physical attributes of the system and those involving the correct allocation of costs in the system are essentially the same now as they were at the time of the merger.

67. In the Second Supplemental Order on the merger, the Commission noted that the uncontradicted evidence in the record projected substantial benefits from the merger, and stated that "the Commission's concern was that Washington ratepayers receive an equitable share of the benefits." *Id*., p. 13. Of particular importance for the instant case, the Commission took note of "the discrepancy in average system cost between Pacific Power and Utah Power." *Id*., p. 14. The Commission went on to state:

> The Commission continues to be concerned about the effects on Pacific's ratepayers of merging with a higher cost system, and believes that *any integration of the power supply function for the two companies should be done in a manner consistent with Pacific's least cost planning process*, now getting under way. In the meantime, the Commission's views Pacific's current average system costs as the appropriate basis for rates.

Id., p. 14 (emphasis added).

68. At the hearing in this case, PacifiCorp introduced an August 1989 letter from the Washington Commission to the Public Service Commission of Utah which addressed the merger and multi-state allocation issues. Exh. No. 469. While PacifiCorp sought to undermine Mr. Lott's testimony with this exhibit on cross-examination, the letter instead offers further support for Mr. Lott's characterization of the merger and of allocation methodologies.

69. On the first page of the letter, the Commission explains why it approved the merger:

> When we approved the merger, we approved it for the benefit of our ratepayers. Most importantly we approved the merger so that our ratepayers would benefit by receiving lower rates over that stand-alone costs that would exits if the merger had not been approved. Further, we held that our ratepayers should not in any circumstance be required to pay more than they would have without the merger.

Exh. No. 469, p. 1.

The Commission recognized the hydro endowment that the Pacific division brought to the merger and that "[s]imply put, Pacific Power was a low cost company and Utah Power a higher one." *Id.*, p. 2. While the Commission did not adopt a specific allocation methodology, it was "not convinced that moving to a fully rolled-in methodology should ever be an objective" or that the divisions should be combined. *Id.*

70. The Commission also attached a Staff paper describing different allocation methods under discussion. The Commission agreed with the concerns expressed in the paper. *Id*. Staff noted that "Washington did not approve the merger with the intent to surrender the Pacific identity to some fully rolled in entity." *Id*., p. 6. Staff's statement addressing "fully rolled in or single system allocation" is particularly noteworthy:

> While this has been shown as an objective of PacifiCorp and the Utah Commissions [sic], it cannot be considered a principal of allocations. As promised in our hearings, this can and should only become the method of allocation when it can be shown that to do so is to the benefit of Pacific customers. There has been no demonstration that this is or will be the case in the foreseeable future.

Id.

PacifiCorp never made that showing, and has failed to do so again in this case. In the Revised Protocol, in fact, resources are "rolled in", including new generation and the capacity benefits of Pacific hydro. Exh. No. 461, p. 7, n.6, pp. 23-24, (Lott).

2. PacifiCorp has never proposed an appropriate cost allocation mechanism in Washington.

71. The Commission has yet to approve a method for allocating PacifiCorp's power costs to customers in Washington. PacifiCorp notes in its Washington Status Report on Interjurisdictional Cost Allocations that the Commission's last order on the issue was issued in 1986. Exh. No. 4, p. 6. In large part, this was because the Company did not file any rate cases in Washington from 1986 to 1999 and parties to subsequent cases did not agree on a methodology. *Id.*, pp. 7-9.

72. The lack of an approved inter-jurisdictional cost allocation mechanism is in large part due to PacifiCorp's failure to propose a fair methodology. A review of the history of the various methodologies proposed and discussed over the years show a common thread between Revised Protocol and the variations on a "rolled in" methodology. Exh. No. 461, p. 7, n. 6, p. 17 (Lott). This is true whether one examines Revised Protocol, Modified Accord, Accord, or earlier versions such as Bold Course. While Revised Protocol includes many exceptions and modifiers, it is still essentially a "rolled in" methodology. *Id.*, pp. 6-17; Exh. No. 1, p. 25, ll.14-17 (Furman).

73. The fundamental problem with the "rolled in" method is that it averages the majority PacifiCorp's power costs across its entire system. *Id.* A "rolled in" method thus creates an advantage for the Eastern control area, which has higher embedded costs, and is incurring higher incremental costs (due to faster load growth), as compared to the Western control area. The Western control area, including Washington State, is disadvantaged because it has lower embedded costs and is not incurring significant new cost (due to lower load growth). Washington did not approve entry into the merger because the combined companies would produce average costs that would benefit Utah customers and burden former Pacific division customers, but because the merger appeared to offer substantial synergies that would reduce costs for all customers in both divisions. Exh. No. 461, p. 22, ll.17-22, (Lott); Exh. No. 469, p.1, ¶ 4.

74. A further critical flaw in Revised Protocol is that it does not meet the original merger order requirement that any inclusion of power costs from the Utah division into to the Pacific division post-merger should be consistent with PacifiCorp's least cost plan. While PacifiCorp now conducts one least cost planning process, it continues to plan for its Eastern and Western divisions separately. Exh. No. 461, p.18, l.19 (Lott); Exh. No. 541, p. 78, ll. 10-20 (Buckley). This is clearly reflected, for example, in the Company's 2003 Integrated Resource Plan, where the portfolio selection discussion and matrix categorize selections according to East and West locations. Exh. No. 148, pp. 159-160. The Company has not demonstrated on this record that resource costs allocated to the Pacific division, and hence to Washington, meet a least cost test for this division.

C. The Revised Protocol Has Critical Flaws.

1. The Revised Protocol does not allocate costs on a "cost causation" basis.

75. The "cost causation" principle was identified in the Staff report attached to the 1989 letter to the Utah Commission. The Staff report noted that "allocation of costs should be made based on some type of cost causation analysis." Exh. No. 469, p. 9. The "Cost Causation" section of the report continued:

> Any type of allocation method that distributes costs on a current rolled in basis without recognizing the endowment, current and future, that the Pacific division brought into the merger fails to recognize the agreement and promises made with the Pacific division regulators, and , therefore, fails to treat the customers of the Pacific division for the costs they caused. As a maximum, the Pacific division customers have caused no more costs than they would have incurred absent the merger.

Id.

76. This principle has not been adhered to in the Company's proposal. As Mr. Lott testifies, "The Revised Protocol fails to allocate individual costs on a cost causation basis using any reasonable basis of cost causation." Exh. No. 461, p. 21, l. 18 (Lott). He points out that many of the allocation techniques in the Revised Protocol are simply conventions intended to achieve a certain result, and are not related to any particular definition of causation. Revised Protocol, like its precursor the "Bold Course" method, fails to use as a starting point the resources that each division brought into the merger as its foundation and fails to add new resources to the division based on the least cost needs of the division. *Id.*, pp. 21-22. "Rolled in" methodologies have failed to accounted neither for differences in how the two divisions of the company operate, nor for the fact that the divisions are a merger of two diverse companies that had substantially different cost drivers. *Id.*, p. 22, ll.14-17.

2. Revised Protocol misallocates costs in a number of ways.

77. Public Counsel's testimony details a series of significant ways in which the Revised Protocol cost allocation is flawed. Exh. No. 461, p. 23-29, (Lott).

78. Hydro endowment. While Revised Protocol assertively provides Pacific division jurisdictions with a hydro endowment, it does not, in fact, give the full advantage of these resources. It only deals with the cost of energy, while ignoring the value of peaking and other benefits from the ability to use hydro power for shaping output. As a result, Pacific division states pay more for capacity than is necessary to meet their demand. *Id*., pp. 23-24.

79. New resources. Revised Protocol allocates new resources to all states based on their share of overall demand or load, rather than allocating them to the division that is experiencing the load growth that requires the new resources. *Id*. p. 24.

80. Fixed costs. Revised Protocol uses the same allocation factor for both control areas (75% demand, 25% energy, using a 12 month coincident peak for determining demand). As discussed in detail in Exh. No. 461, this factor is inherited from an earlier methodology (Modified Accord) designed to meet Utah needs, and differs from the method more appropriate for Pacific states. *Id.*, pp. 24-25.

81. Taxes. The problem in this area is that under Revised Protocol, state income taxes are allocated to all states based on income, while the Washington State revenue tax is allocated on a situs basis. *Id*., pp. 25-26.

82. Fuel costs and non-firm purchases. Revised Protocol allocates these items on an energy basis. These allocations are based on a convention, however, rather than on actual cost causation. The method does not reflect that the usage of energy is seasonal in the two divisions, that the seasons are opposite (winter vs. summer usage), that the mix of use of power plants is different, that the markets for purchased power are different regionally and seasonally, and that market prices vary substantially between seasons. As a result, there is a significant probability that the costs are different in the two seasons and the Pacific division has lower costs than the Utah division. *Id*., p. 26.

83. <u>Qualified Facilities</u>. Allocation of these costs is also done on a convention basis, rather than on cost causation. Although in this case Washington benefits from the approach, the methodology is inappropriate. *Id*., p. 27.

84. <u>Off-system sales</u>. Revised Protocol allocates these sales on an energy basis when non-firm and on a system generation basis when firm. Again, this does not match cost causation. Regulated utilities, unlike Independent Power Producers, are not in the business of acquiring generation for the sole purpose of profiting in the market. The proper allocation should be: (1) to offset the incremental variable costs associated with the sales, and (2) to allocate the net benefit of the sales to offset the fixed costs that were incurred to enable the benefit in the first place. *Id*., p. 27.

85. <u>Seasonal Resources</u>. Public Counsel does not object to the way the Company proposes to consider seasonal resources, but allocation of the fixed costs should be consistent with the total allocation process and with the intended and actual use of the facilities. The inconsistent treatment of cost allocation for the Cholla Power Plant (Unit 4), detailed in Mr. Lott's testimony, is one example of how the Revised Protocol does not appropriately treat seasonal resources. *Id*., pp. 27-28.

D. The Utah Division Has Experienced Substantially More Growth Than The Pacific Division.

86. In discovery, Public Counsel requested growth information for all jurisdictions served by PacifiCorp. The responses are compiled in Table C in Mr. Lott's testimony. Exh. No. 461, p. 42. They show that over that past 14 years, the Utah division has grown over 7 million MWh compared to the Pacific division's increase of less than 2 million MWh (excluding Idaho and Montana.) *Id*.; *see also*, p. 43, ll. 1-7. Since 1989, the Pacific division has shown a 2.91 percent total load growth while the Utah division has grown 38.19 percent. This indicates that Pacific division's pre-merger plant has, as a general matter, remained adequate to meet its needs. New system resources post-merger have been required to serve new growth in the Utah division. Allocation of those new resource costs system-wide, therefore, over-allocate costs to the Pacific division, with the Pacific division paying for substantially more resources than it requires. Under the Revised Protocol, all states and divisions are allocated a share of all resources, new and old equally, without consideration of the growth which required the addition of the new resources. Exh. No. 461, p. 41, ll. 6-9 (Lott).

E. Adoption by Other States Does Not Justify Adoption of Revised Protocol In Washington.

87. PacifiCorp attempts to use an "odd man out" rationale to persuade the Commission to adopt the Revised Protocol, arguing that the approach has been adopted widely throughout PacifiCorp's territory. Exh. No. 1, p. 27, ll. 9-12 (Furman). The Commission should reject this rationale for a number of reasons.

88. First, PacifiCorp acknowledges that several of the states that have adopted the Revised Protocol have higher embedded costs and are incurring higher incremental costs than Washington. Exh. No. 4, p. 2. For these states, Revised Protocol is an attractive option and advantageous to them. They pay less than they would on a stand alone basis because they benefit from the averaging in of lower costs from other states.

89. Secondly, it is misleading to claim that other states have uniformly adopted Revised Protocol. In fact, each state that has adopted it has made a variety of special-case modifications designed to protect its own customers. Exh. No. 541, pp. 41-43 (Buckley).

90. Finally, states that have adopted the Revised Protocol have reserved the right to discontinue using the method and change to an alternative cost allocation method in the future.

91. For these reasons, the PacifiCorp argument that the Washington Commission should fall into step with other states loses its force, given that there is significant lack of uniformity between the states when one looks beneath the surface. The Washington Commission should decide this issue on the merits, not because of what other states have done.

F. PacifiCorp Has Failed To Show That Revised Protocol Has Accurately Allocated Power Costs To Washington Customers.

1. PacifiCorp operates two control areas.

92. PacifiCorp operates two separate electric control areas. With certain exceptions, the Eastern Control area includes the loads and resources that were part of Utah Power, and the Western control area includes the loads and resources that were part of Pacific Power & Light. The Eastern and Western control areas cover geographically distinct regions. Exh. No. 331, p. 4, ll. (4-14) (Duvall).

93. PacifiCorp plans, schedules and dispatches resources located in the Eastern Control area to serve the majority of the needs of its customers in the Eastern control area. PacifiCorp plans, schedules and dispatches resources located in the Western Control area to serve the majority of the needs of its customers in the Western control area. *Id.*, p. 5, ll.1-4.

94. Under certain conditions and to a limited extent, PacifiCorp is able to transfer power from its Eastern control area to help serve loads in its Western control area and vice versa. However, the amount of firm transmission capacity that PacifiCorp has available to make such transfers is constrained. Exh. Nos. 347, 348. PacifiCorp's firm transmission is significantly more constrained from East to West than from West to East.

95. PacifiCorp also has several long-term power exchange contracts, including some that can be used to transfer power between the Eastern and Western control areas. Exh. No. 331, p. 40, l. 21 - p. 41. l. 3; p. 44, ll. 3-8 (Duvall). However, the amount of firm power that can be transferred from one control area to serve loads in the other control area under these agreements is also limited.

96. Transfers between PacifiCorp's Eastern and Western control areas and use of its long-term power exchange contracts enable PacifiCorp to capture some efficiencies from its multi-state power system. *Id.* However, such efficiencies do not guarantee that customers in Washington State are protected from transfer of value from PacifiCorp's Western control area to its Eastern control area.

97. In operating its two control areas, PacifiCorp is required to comply with standards established by the North American Electric Reliability Council (NERC) Minimum Operating Reliability Code. Exh. No. 331, p. 4, ll.16-18 (Duvall). These standards include the requirement that only firm resources and firm transmission (including transmission between the Eastern and Western control areas) be scheduled to serve expected firm loads. As a result, PacifiCorp effectively uses two separate portfolios of electric resources to serve two separate sets of retail electric loads. One portfolio of resources and loads is located essentially within PacifiCorp's Western control area, and the other portfolio of loads and resources is located essentially within PacifiCorp's Eastern control area.

2. Physical characteristics and operational data of the PacifiCorp system indicate that a control area methodology is a feasible approach to allocation.

98. PacifiCorp has argued that its power system is highly complex and that it would not be possible to develop an inter-jurisdictional allocation method that reflects its two portfolios of loads and resources. Exh. No. 331, p. 13, ll.10-22 (Duvall). However, PacifiCorp operates its integrated power system on this basis every hour of every day, including scheduling the operation of its generating resources, inter-control area power transfers and use of its long-term power exchange contracts.

99. Public Counsel believes that a control area method for allocating PacifiCorp's power costs to Washington State could be developed and could be less complex than the Revised Protocol. Development of such a method would provide a much better basis for ensuring that power costs are allocated accurately and equitably. In particular, the control area method would prevent inordinate cost shifting from the Eastern control area onto Washington State.

100. While PacifiCorp has a responsibility to propose a method that accurately and equitably allocates its inter-jurisdictional power costs to Washington State, efforts to work with PacifiCorp in development of a straightforward and practical control area method have proved difficult. Exh. No. 753.

101. Public Counsel has taken an initial step toward investigating whether a control area method would be possible by examining actual transfers of power between PacifiCorp's Eastern and Western control areas from October 1, 2004 through September 30, 2005. Exh. No. 357.

102. Data provided by PacifiCorp for transfers from its Eastern control area to its Western control area during October 1, 2004, through September 30, 2005, show the following:

- During the 12-month period, PacifiCorp transferred an average of just 31 megawatts per hour of power (271,928 megawatt-hours) from its Eastern control area to its Western control area. Exh. No. 357, pp. 3-47. This amount represented just 1.4 percent of retail load in PacifiCorp's Western control area during the same period. Exh. No. 358.[4]
- The highest hourly retail load level reached in the Western control area during the 12-month period was 3,492 megawatts. Exh. No. 358, p. 26. During that hour, ending at 8:00 a.m. on January 5, 2005, PacifiCorp transferred 504 megawatts of power from its Western control area to its Eastern control area. Exh. No. 357, p. 59.

In other words, during the peak load hour of that year for the Western control area, no resources from PacifiCorp's Eastern control area were needed to serve load in its Western control area – in fact, PacifiCorp was transferring 504 megawatts of power out of the Western control area to the Eastern control area.

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[4] The referenced exhibits are in the record as hard copy print-outs of CDs provided by the Company in response to Public Counsel Data Requests. The CDs presented the data in Excel spreadsheet form which enabled Public Counsel to perform the calculations discussed here. The average megawatts per hour was calculated by summing all of the hourly amounts and dividing by the total hours shown on Exh. No. 357. The percent of retail load was calculated by summing the total megawatt hours of transfers shown in Exh. No. 357 and dividing by the sum of the retail loads shown on Exh. No. 358.

103. These actual operating data indicate that the relative magnitude of transfers from PacifiCorp's Eastern control area to its Western control area is quite small on an energy basis and can even be negative on a peaking basis. This supports Public Counsel's view that existing resources in PacifiCorp's Western control area are largely sufficient to serve loads in the Western control area, and that a control area method for allocating power costs could be developed.

104. Data provided by PacifiCorp for transfers from its Western control area to its Eastern control area during October 1, 2004, through September 30, 2005, show the following:

- During the 12-month period, PacifiCorp transferred an average of 307 megawatts per hour of power (2,686,941 megawatt-hours) from its Western control area to its Eastern control area. Exh. No. 357, pp. 48-92. This amount represented 7.9 percent of retail load in PacifiCorp's Eastern control area during the same period. Exh. No. 359.[5]
- The highest hourly retail load level reached in the Eastern control area during the 12-month period was 5,840 megawatts. Exh. No. 359, p. 90. During that hour, ending at 3:00 pm on July 21, 2005, PacifiCorp transferred 817 megawatts of power from its Western control area to its Eastern control area. Exh. No. 357, p. 83.

These actual operating data indicate that while power transfers from PacifiCorp's Western control area to its Eastern control area were larger than power transfers from East to West, they were not large enough to create a significant impediment to developing a control area method for allocating PacifiCorp's power costs.

105. However, the data for actual power transfers between PacifiCorp's two control areas raises new concerns that the value of power transfers from the Western control area to the Eastern control area is much larger than the value of power transfers in the opposite direction. The amounts provided above show that PacifiCorp transferred 307 average megawatts of energy from West to East, but only 31 average megawatts from East to West. Meanwhile, 817

[5] See previous footnote. These calculations were performed in the same manner.

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Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012

megawatts of power was transferred from the Western control area during the 12-month peak hour in the Eastern control area, but 504 megawatts of power was transferred from the Western control area during the 12-month peak hour in the Western control area (i.e., no power was transferred from the Eastern control area to help meet the peak-hour load in the Western control area).

106. Much of the attention on inter-jurisdictional cost allocation has been focused on the Revised Protocol and its implementation via PacifiCorp's highly complex GRID model, which in theory models system operation for determining costs to be allocated. Public Counsel's review of actual data for power transfers between PacifiCorp's Eastern and Western control areas, however, leads to two conclusions:

1. A control area method for allocating power costs can be developed and likely will produce a more accurate allocation of costs to Washington State.
2. The net flow of power transfers during a recent 12-month period was strongly in the West to East direction. This demonstrates that the new resources PacifiCorp is acquiring in its East control area are not needed or used to serve customers in the Western control area, including Washington State. Further, it raises concerns that significant net value is being transferred from the Western control area to the Eastern control area. As such, it further supports the value and importance of developing a control area method for allocating PacifiCorp's power costs.

107. Development of a control area method for allocating PacifiCorp's power costs would not interfere with coordinated operation of PacifiCorp's Eastern and Western control areas and would not limit PacifiCorp's ability to capture system efficiency gains.

G. PacifiCorp Must Establish That Resources Added To Its Power Supply Portfolio Were Prudently Acquired Before Costs Can Be Allocated To Washington Customers.

108. PacifiCorp must meet a burden of proof to demonstrate that the new resources it has acquired are prudent. *WUTC v. Puget Sound Energy*, Docket No. UE-921262, Eleventh

Supplemental Order, p. 23. In the context of inter-jurisdictional cost allocation, this principle requires that PacifiCorp show that resource costs that are allocated to Washington through whatever methodology is employed must have been prudently incurred. This is of particular importance with a methodology such as Revised Protocol because, to the extent system-wide costs (including costs from the Eastern control area) are "rolled in" and charged to Washington, they must be shown to be prudent. Public Counsel submits that PacifiCorp has not done so here. This provides another reason why adoption of Revised Protocol is inappropriate.[6] This section of the brief discusses how PacifiCorp's evaluation process for new resource acquisition contains significant weaknesses.

109. PacifiCorp is a vertically integrated, Commission-regulated utility whose retail electric rates are based on cost of service. A demonstration of prudence would include showing that the specific new resources PacifiCorp has acquired are ones that will best enable it to provide low-cost, reliable service, within acceptable risk and without undue environmental impacts. The appropriate basis for evaluating specific new resource acquisition candidates is in terms of their net impacts on the portfolio of resources that PacifiCorp uses to serve its customers. Exh. No. 471, p. 4, ll.5-13; p. 6, ll. 9-14 (Black). However, the processes and analyses that PacifiCorp used to evaluate and compare specific resource acquisition candidates were inadequate and inappropriate. *Id*., p. 4, ll. 14-23.

110. PacifiCorp evaluated specific new resource acquisition candidates on a stand-alone basis, without addressing how they will impact cost, reliability, risk or environmental impacts for its portfolio of electric resources. *Id.,* p. 11, l. 6- p. 12, l. 3. In its stand-alone evaluations of specific new resource acquisition candidates, PacifiCorp used mark-to-market valuations as a primary benchmark for evaluation and comparison. Mark-to-market valuations do not provide

[6] Public Counsel would further observe that the process of evaluating prudence of resources acquired to serve new and growing loads in the Eastern control area, a prerequisite to imposing any part of their costs on Washington customers, would be burdensome in terms of time and resources. The need to perform this review would be avoided under the type of control area/divisional allocation method proposed by Public Counsel.

relevant or sufficient information to select new long-term resources to meet the needs of a vertically integrated utility's customers. *See generally*, Exh. No. 471, pp 20-24 (Black).

- Mark-to-market value is a financial indicator that provides a single point estimate of the commercial trading value of a specific resource acquisition opportunity, measured relative to a forecast of market prices for wholesale power.
- Mark-to-market valuation is typically used for commercial trading and financial reporting purposes. It focuses on market value, not on minimizing the cost of service to serve retail electric customers. This characteristic alone makes mark-to-market valuation an inappropriate tool for making long-term resource acquisition decisions.
- The results of a mark-to-market valuation provides no indication of risks, including risks for the specific resource acquisition opportunity or impacts that the specific resource acquisition candidate would have on risk for a utility's overall portfolio of electric resources.
- Any long-term forecast of market prices for wholesale power is highly uncertain. As a result, the results of mark-to-market valuations are highly uncertain.
- Mark-to-market values provide no indication of how well or how poorly any specific resource acquisition candidate would fit the utility's need for new resources. One resource acquisition candidate may have an attractive mark-to-market value, but be a poor fit with the utility's resource need (e.g., a base load year-round resource for a utility whose need for new resources is concentrated in one part of the year).
- Mark-to-market values provide no indication of how well or how poorly any specific resource acquisition candidate would interact with the utility's existing portfolio of resources. For example, one resource acquisition candidate may have an attractive mark-to-market value, but it may increase an already high concentration of one type of resource in the utility's portfolio. This can lead to

various problems, including creating excessive exposure to fuel price risks for one type of resource or failure to add new resources to provide sufficient operating flexibility for the utility's overall portfolio.

111. PacifiCorp claims that Navigant Consulting's Final Report on PacifiCorp's RFP 2003-A Exh. No. 432, p. 48 (Tallman) found that the process and methods PacifiCorp has used to acquire new resources are consistent with industry practices. Quoting a report from a consultant that PacifiCorp has hired does not meet PacifiCorp's burden of proof to demonstrate prudence under this Commission's standards. Further, the Navigant report clearly shows that PacifiCorp did indeed rely heavily on the results of mark-to-market valuations, with the various shortcomings that Public Counsel lists above.

112. PacifiCorp has attempted to claim that its use of mark-to-market valuations was appropriate because they are "required under applicable accounting rules." Exh. No. 440, p. 1, l. 18 (Tallman). However, this requirement is associated with FAS-133, which deals with reporting of a company's short-term financial results and has no bearing on long-term resource acquisition decisions by regulated utilities.

113. PacifiCorp uses an extensive portfolio evaluation process in its Integrated Resource Planning (IRP) process. Exh. No. 471, p. 5, l. 22- p. 6, l. 8 (Black). However, PacifiCorp has not demonstrated that its evaluation and comparison of specific resource acquisition candidates was consistent with either the resource strategy from its IRP or the portfolio evaluation methods used in its IRP.

114. PacifiCorp claims that the IRP provides guidance for its resource acquisitions, Exh. No. 440, p. 6, ll.18-20 (Tallman), but has not identified that it uses any mechanism to ensure that the new resources it actually acquires are consistent with the IRP resource strategy, either individually or in aggregate.

115. PacifiCorp performed its evaluations of specific resource acquisition candidates on a stand-alone basis. PacifiCorp did not perform portfolio evaluations for any of its new resource acquisitions and therefore did not assess the impacts of specific candidate resources on cost, risk, reliability or environmental impacts for its overall portfolio of electric resources.

116. In its description of the stand-alone evaluations it performed on proposals received in response to its September 2001 RFP, PacifiCorp identifies the criteria that were used. Exh. No. 421, p. 5, ll.1-10 (Tallman). However, PacifiCorp has not described how it used its criteria to select specific resources for acquisition, including the relative weights applied to each criterion or the results of its application of the criteria. Further, the criteria were not related to PacifiCorp's IRP resource strategy and did nothing to overcome the limitations associated with mark-to-market valuation described above.

117. PacifiCorp states that it designed its currently-filed supply-side RFP to use a production cost model. Exh. No. 440, p. 5, ll. 21-23 (Tallman). Production cost models can be used to evaluate specific new resource acquisition candidates from an integrated resource portfolio perspective. As such, Public Counsel applauds PacifiCorp's decision to move in this direction. However, such a change can improve PacifiCorp's resource acquisitions only in the future, and does nothing to demonstrate that its recent resource acquisitions were prudent.

118. PacifiCorp misrepresents the testimony of Public Counsel witness Charles J. Black regarding use of production cost models. Exh. No. 440, p. 5, l. 19 – Page 6, l. 2. Nowhere in his testimony does Mr. Black state that production cost modeling is the only valid method to evaluate specific new resource acquisition candidates. Instead, Mr. Black has noted that PacifiCorp performed its evaluations on a stand-alone basis and has shown why such evaluations are not adequate to identify new resource acquisitions that best promote the objectives of cost, risk, reliability and environmental impacts for the utility's portfolio of electric resources. Again, PacifiCorp has not shown that the stand-alone evaluation methods it used, including mark-to-market valuation, enabled it to identify resources that meet such objectives for its electric resource portfolio.

H. Public Counsel Recommends an Alternative for Multi-state Cost Allocation.

119. Public Counsel recommends that the Commission reject the Company's Revised Protocol methodology proposed in this docket as a means to determine allocation of costs to Washington. As an alternative, for the reasons described above, Public Counsel recommends that the Commission direct PacifiCorp, Commission Staff, and other interested parties to develop a portfolio approach to cost allocation on a Pacific division, control area or portfolio basis.

120. Public Counsel's approach, as proposed by Mr. Lott, would start with the divisional resources of the former Pacific Power & Light Company and then establishes a portfolio for either the Pacific division or for Washington. Additional resources should be based on those resources acquired since the merger to serve Western control area needs, which provide the required energy and capacity and can be physically delivered. Neither resources of the Utah division nor new resources acquired in the Eastern control area should be allocated to Washington unless the resources can be shown to be consistent with the least cost plan to serve the Pacific load and are deliverable to Pacific states. *See* Exh. No. 461, pp. 20-21 (Lott).

121. Public Counsel witness Charles Black presents a variation on this theme, which provides another alternative based on the same principles. The method involves three basis steps. First, power costs that Revised Protocol currently aggregates on a system-wide basis are assigned instead to two separate portfolios ("U" and "P"). Second, power costs from portfolio "P" are allocated to Washington state and other portions of the system served by portfolio "P" on a primary basis. Third, specific Washington power costs are calculated by adding the state's share of portfolio "P" costs to any Washington-specific cost. Exh. No. 471, pp. 43-45 (Black).

122. Public Counsel believes that this alternative approach, in either variant, will lead to a more accurate and equitable multi-state allocation than the Revised Protocol.

VII. POWER COST ADJUSTMENT MECHANISM

A. Overview.

1. PacifiCorp's proposal is not in the public interest.

123. The testimony of Public Counsel witness Merton Lott explains why PacifiCorp's proposed power cost adjustment mechanism (PCA)[7] is not in the public interest. Exh. No. 461, p. 44, *et seq*. The Company's plan does not follow the Commission's prior guidance on how a PCA should be structured. *Id*. The PacifiCorp PCA is inconsistent in important respects with components of the PSE and Avista mechanisms. A major shortcoming is in the treatment of fixed power costs. *Id.*, p. 51.

2. A PCA cannot be designed for PacifiCorp until after a cost allocation method has been adopted.

124. A threshold question with regard to design and approval of a PCA in this docket is the outcome of the multi-state allocation issue. Until that is determined, the Commission will find it very difficult or impossible to design a reasonable PCA for the Company. This is because Washington's jurisdictional responsibility for power costs is ultimately determined by the cost allocation method selected. Exh. No. 416, p. 47, ll. 15-24 (Lott). Without an interjurisdictional allocation methodology, the Washington Commission cannot determine the actual costs attributable to ratepayers from a PCA. *Id.* (describing example of fuel purchase).

B. Prior Commission Guidance.

125. The principles identified by Mr. Lott in his testimony are derived from the past decisions of the Commission which provide well-established guidance for the proper structuring of power cost adjustment mechanisms. Exh. No. 461, pp. 44-45 (Lott). The Commission has announced three broad policy goals: (1) a power cost adjustment mechanism should be linked to factors that are weather related; (2) a power cost adjustment should be a short-run accounting procedure that reflects the short-run cost changes affected by unusual weather, whereas the prudency of long

[7] Public Counsel will use the standard acronym for power cost adjustment mechanism in this brief -- PCA, rather than the "PCAM" variation used by Pacificorp.

run resources is the proper subject for a general rate case; and (3) where a PCA is established, rate payers should receive the benefit of a cost of capital reduction. *See, e.g.,WUTC v. Puget Sound Power & Light,* Docket Nos. U-89-2688-T, U-89-2955-P, Third Supplemental Order, pp. 13-15; *WUTC v. Washington Water Power*, Docket No. U - 89-2363-P, First Supplemental Order, p. 8. In Avista's 1999 general rate case decision in 2000, the Commission reaffirmed the policy goals set out above. *WUTC v. Avista*, Docket Nos. UE-991606, UG-991607, Third Supplemental Order, ¶¶ 16-17.

126. In Avista's most recent general rate case, Public Counsel and ICNU raised concerns about modifications to the Avista Energy Recovery Mechanism (ERM) agreed to by Staff and the Company, on the ground that they unduly shifted risk to ratepayers. The Commission declined to adopt the proposed changes and ordered a separate proceeding to consider whether, *inter alia*, "[o]n the basis of more fully developed record, we may determine that adjustments to the deadband and other features of the ERM will result in a more effective balance of risks than is currently in place." *WUTC v. Avista Corporation d/b/a Avista Utilities*, Docket Nos. UE-050482, UG-050483, Order No. 05, ¶ 73. Avista has now filed a petition to initiate that docket.

C. When Measured Against Six Fundamental Criteria Derived from Commission Precedent the PacifiCorp PCA Falls Short.

127. Mr. Lott's direct testimony sets out six criteria derived from Commission precedent in this area. Exh. No. 461, pp. 45-47 (Lott). The testimony discusses in detail how PacifiCorp's proposal fails to adequately meet these standards. *Id.*, pp. 48-50.

1. The PCA impact must be understandable to customers.

128. The first criterion is that the impact of the PCA needs to be logical and understandable to the ratepayer in its application so that customers can see the connection between the weather events, or other uncontrollable factors, and the increased rates that result from the PCA. PacifiCorp's proposal here does not meet this test because it includes costs that are not out of PacifiCorp's control, such as new contracts (see below), that can trigger deferrals and surcharges for which ratepayers will be responsible, while the customer will see no external event that would demonstrate a need for the rate change.

2. The PCA should only allow deferrals when the total cost of service has increased.

129. While the proposed PCA includes wheeling revenues and expenses, it does not measure PacifiCorp's total cost of transmission required to bring resources to is retail customers. By failing to include transmission rate base and associated expense, it understates the embedded cost PacifiCorp is currently incurring. This is because when a new purchase is made, both the purchase and the wheeling expense (transmission to deliver the power) are included, and are compared to an embedded cost which fails to include that same transmission. As a result, a deferral can occur, even though the total cost per unit did not increase. Company witness Ms. Omohundro did not address this concern.

130. The adoption of a decoupling mechanism does not eliminate this problem. Power costs are measured on a per kWh basis, while decoupling measures the fixed costs on a customer basis. This divergent treatment of like costs (wheeling and transmission system) is inappropriate.

131. As Mr. Lott discusses in his testimony, this criterion also addresses the fact that fixed costs may decline or disappear when major plant outages or terminations occur. This is the reason for the Colstrip adjustment in the PSE PCA. Exh. No. 465, p. 48-49 (Lott). PacifiCorp's PCA has no such adjustment to protect ratepayers from problems caused by poor reliability. As a result, the variable cost recovery built in to the PCA will over-recover cost because it will not reflect the reduction in fixed costs as an offset. Because PacifiCorp has more major plants in its system than PSE, this issue is even more of a concern.

3. Cost increases should be allowed only for items truly beyond Company control.

132. The proposal appears to be expressly designed to disregard this core criterion, and the Commission orders upon which it is based (see discussion above). While the PCA does reflect the impact of stream flows and market conditions, Ms. Omuhundro acknowledges on rebuttal that it is also designed to recover cost increases associated with purchasing new generation. Exh. No. 383, p. 5, l. 20 (Omohundro). Nothing about this type of cost is beyond the Company's control. In addition to violating Commission orders on this point, this component is further problematic in that it provides divergent treatment for resource acquisitions from purchased power versus those from buying or building generation. This inconsistent treatment creates perverse incentives in the resource acquisition process.

4. Ratepayers should be compensated for the reduction of risk.

133. By including no deadband, PacifiCorp's proposal shifts a dramatic amount of risk to ratepayers. This Commission has stated that it is incumbent on a Company to provide specific compensation to customers for such a shift. PacifiCorp has not proposed a reduction in its rate of return in this case, nor has it identified any other form of compensation for ratepayers. Exh. No. 461, pp. 49-50 (Lott).

5. The utility should not be completely shielded from risk at any point.

134. PacifiCorp meets this criterion, since its proposal is based on sharing band of 90 percent/10 percent at all cost levels.

6. Long term costs should not be deferred through the mechanism.

135. PacifiCorp's PCA includes increases in contract rates. Existing long term contracts may well have cost increases embedded within them. These contract terms are hardly beyond the control of PacifiCorp and should not be treated as such for PCA purposes. Long term contracts represent cost increases for a subset of resources, without looking at all cost resources combined. The timeline and direction of the cost level for a particular resource is impacted by PacifiCorp's decision whether to own resources or purchase under contract. In general, resources purchased under contract show increasing cost lines, while owned resources show declining or stable cost lines (rate base declines). Significantly, one hundred percent of contract purchases are included in PacifiCorp's PCA (within the variable costs), while, other than fuel, costs of owned resources are treated as a fixed cost. Thus, as constructed, the PCA creates an incentive for the Company to invest in contract resources, even where cost increases can be predicted.

D. The Proposed PCA Does Not Stand Up To A Comparison With The PSE PCA.

136. Some of the testimony on the PCA issue in this case discusses comparisons with other extant mechanisms. PacifiCorp supports its proposal, in part, by stating that it was patterned after the proposed ERM put forward by Avista in its last rate case. Exh. No. 383, p.4, ll. 14-16 (Omohundro), TR. 539:21-540:4**.** This is not particularly helpful to the Company's cause. Avista's original proposal in testimony involved eliminating the deadband. This was not ultimately presented to the Commission. Instead, Avista and Commission Staff presented a compromise proposal for a much reduced deadband. In the end, the Commission was not comfortable approving this level of risk-shifting and declined to adopt the settlement. *WUTC v. Avista*, UE-050482, UG-050483, Order No. 05, ¶¶ 63, 71-77. Avista's original ERM, adopted in the context of financial difficulties, was not intended as a fully developed or permanent PCA, and was scheduled for review in 2006, a review that is now beginning. *Id.*, ¶¶ 74-76 (regarding review). Public Counsel's testimony and briefing in the Avista rate case explored a number of structural changes needed to make the ERM a properly designed mechanism comparable to the PSE PCA. *Id.*, ¶ 67. For these reasons, comparisons to the Avista ERM are of little value in evaluating the proposal in this case.

137. By contrast, the PSE PCA provides the best template against which to measure the PacifiCorp plan. Public Counsel's testimony in this case points out the key differences in the course of discussing the applicable criteria for PCA design. Public Counsel's response to Bench Request No. 23, Exh. No. 761, summarizes the comparisons between the three plans, correcting and supplementing the Company's response to this request.

E. PacifiCorp Has Not Shown A Compelling Need for a PCA At This Time.

138. PacifiCorp has had a steady series of rate increases and rate proceedings since 2000. Under its five year rate plan adopted in 2000, PacifiCorp received agreed increases in 2000,

ATTORNEY GENERAL OF WASHINGTON
Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012

2001, and 2002. TR. 535:14-536:1. Although it had agreed to a two year rate freeze in 2004 and 2005, PacifiCorp abrogated the agreement by filing in 2002 for permission to place alleged "excess power costs" in a deferral account. The Commission rejected the Company's petition, but effectively terminated the rate plan by allowing PacifiCorp to file for new rates immediately. *In re the Petition of Pacific Power & Light Co.*, Docket No. UE-020417, Sixth Supplemental Order; TR. 536:2-537:21. Over Public Counsel and ICNU opposition, the Company was allowed to file a new rate case in 2003, with rates going into effect in 2004. *WUTC v. PacifiCorp,* UE-032065, Sixth Supplemental Order. It filed the instant docket in 2005, seeking further rate increases for 2006, and has publicly stated that it intends to file another rate case in summer 2006. Given this track record, and the Company's own predictions for the future, any Company concerns about its regulatory lag for its baseline power cost recovery levels can best be addressed in the rate cases it will file. Given the ability to employ future test years for power cost projections, the fact that there is very limited lag when cases are annual, and the fact that with the ordinary 10 month timeline of cases, PacifiCorp will be before the Commission almost continuously, there is no practical need for the Company to have a PCA at this time.

F. Before The Commission Authorizes A Power Cost Adjustment Mechanism (PCA), PacifiCorp Must First Demonstrate That Its Resource Decision-Making Processes Have Been Modified To Provide Proper Incentives And Are Adequate To Meet The Needs Of Retail Electric Customers.

139. PacifiCorp shareholders currently bear the risk of variability in its net power costs. In particular, upward variations in net power costs flow through to shareholders as reduced earnings. Exh. No. 1, p. 20, ll.10-19 (Furman) As a result, PacifiCorp currently has strong incentives to limit variability in its net power costs.

140. In this general rate case, PacifiCorp proposes a PCA that would shift 90 percent of variations in PacifiCorp's net power costs from its shareholders to its retail electric customers. Exh. No. 391, p. 31, ll.18-p. 32, ll. 4 (Widmer). As a result, 90 percent of upward variations in net power costs would flow through to customers as increases to their retail electric rates.

PacifiCorp's PCA proposal would reduce its shareholders' exposure to just 10 percent of the variability in its net power costs. This could dramatically reduce PacifiCorp's incentives to limit variability in its net power costs. Under the PCA, PacifiCorp would retain sole responsibility for managing its electric resource portfolio, including making and executing decisions that affect actual variations in its net power costs.

141. PacifiCorp's PCA proposal would effectively make PacifiCorp the agent of its retail electric customers with regard to management of variability in net power costs. However, PacifiCorp's proposed PCA does not identify any of the changes that need to be instituted to create proper incentives for PacifiCorp to make and execute decisions that reflect the needs and interests of its retail electric customers who would bear 90 percent of the variability in net power costs.

142. Before a PCA can be implemented, significant changes need to be made to PacifiCorp's resource acquisition and energy risk management processes.

1. Resource acquisition.

143. The degree of variability in a utility's net power costs is affected by the configuration of its portfolio of electric resources. For example, a portfolio that includes a larger proportion of natural gas-fired generation has a greater exposure to volatility in market prices for natural gas. Exh. No. 471, p. 42, l. 3 - p. 43, l. 5 (Black).

144. PacifiCorp is engaged in an ongoing process to acquire more than 2,300 megawatts of new resources. Exh. No. 1, p. 7, ll. 8-9 (Furman). Choices that PacifiCorp makes will dramatically affect the exposure of its portfolio to variability in net power costs.

145. However, as discussed earlier in the multi-state cost allocation section, the methods that PacifiCorp has recently used to evaluate specific new resource acquisition candidates do not address impacts on its electric resource portfolio. *See also*, Exh. No. 471, p. 4, *et. seq.* (Black). Thus, PacifiCorp's recent decisions to acquire new resources did not address how they would impact future variability in its net power costs.

146. PacifiCorp has not demonstrated that the process it will use to acquire new resources in the future would adequately address the need to limit variability in net power costs for its electric resource portfolio. This issue is covered in more detail in the section discussing prudence in the acquisition of new resources (multi-state allocation section).

2. Energy risk management.

147. It is not possible or cost-effective to configure a portfolio of electric resources to completely eliminate variability in a utility's net power costs. Therefore, PacifiCorp and other utilities have implemented energy risk management programs to identify and manage various sources of risk that can cause variability in net power costs. Exh. No. 471, p. 49, l. 8 – p. 50, l. 5 (Black)

148. PacifiCorp's existing energy risk management program, including its Energy Risk Management Policy, was developed for the current situation where PacifiCorp shareholders bear the entire risk of variability in net power costs.

149. Public Counsel believes that before 90 percent of the risk of variability in net power costs is shifted to retail electric customers, changes must be made to PacifiCorp's energy risk management program, including creating specific incentives for PacifiCorp employees to manage risks of increased costs to retail electric customers. PacifiCorp's PCA proposal does not identify any such changes to its energy risk management program.

150. In addition, shifting 90 percent of the risk of variability in net power costs from shareholders to retail electric customers would make it essential that PacifiCorp's energy risk management decisions and actions be made more transparent and subject to external review. PacifiCorp's PCA proposal does not identify any mechanism for improving transparency or a process for external review.

151. PacifiCorp argues that no further changes are needed to implement a PCA because it has an energy risk management program and is preparing to use a production cost model to evaluate proposals it receives in response to its current supply-side RFP. Exh. No. 440, p. 9, (Tallman).

This argument is an attempt to sidestep the problems and changes described above that would need to be resolved before a PCA can be implemented for PacifiCorp.

VIII. DECOUPLING

A. Overview.

152. The Natural Resources Defense Council (NRDC), through witness Ralph Cavanagh, has proposed a so-called “decoupling” mechanism that, according to his testimony, would provide assurance that PacifiCorp would fully recover its “fixed cost revenue requirement” regardless of changes in sales volumes. Exh. No. 671, pp. 15-16.

153. NRDC, however, did not present a detailed proposal, an example of how it would work, or the accounting procedures which would be needed to implement his proposal. Ms. Steward, for Staff, termed Mr. Cavanagh’s proposal “rather generic.” Exh. No. 701-T, p.11, l. 18. In cross-examination, she clarified that it was “rather vague” with many details left unresolved. TR. 1154.

154. The NRDC proposal does not even include a calculation of the seminal “revenue per customer” figure that would result from the proposed mechanism. TR. 1069 (Cavanagh). The Company did not prepare such a calculation. TR.1145 (Omohundro). The proposal did not include the deferred accounting mechanism that would be required to implement the proposal, although the Company recognized that it would require some form of deferred accounting. This contrasts to other deferred accounting mechanisms that are fully explained and detailed in proposals to the Commission. TR. 1144 (Omohundro). The NRDC decoupling proposal fundamentally changes ratemaking, from a cost-based approach to one that ties revenues to the number of customers served. A fundamental change in ratemaking, like that proposed by NRDC, should receive cautious, thorough, and analytic examination by the Company prior to a decision of whether or not to endorse the proposal. It is curious that the Company has done no such analysis but is still supporting the proposal.

ATTORNEY GENERAL OF WASHINGTON
Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012

B. The Proposed Mechanism Would Be A Profit Center for the Company.

155. Mr. Cavanagh testified that a 1 percent reduction in sales, due to conservation, would "automatically inflict almost $21 million in losses on PacifiCorp shareholders" (Exh. No. 671, p.2 (Cavanagh)) based on an overly simple analysis he presented. Exh. No. 672. He started with the lost revenues that the Company would experience if sales declined, subtracted the average "variable" costs that would no longer be incurred, and assumed that all other costs and revenues would remain static.

156. Mr. Cavanagh did not appear to consider that the Company would have options other than reducing output uniformly across all of its power plants. In fact, it could either (a) reduce output from plants with higher-than-average variable costs, like the Hermiston gas-fired generating plant, or (b) continue to produce the same amount of power, but sell that power in the wholesale market.

157. Public Counsel witness Jim Lazar did a much more detailed analysis of the decoupling proposal. He used a forecast of market prices provided by PacifiCorp to measure the revenues that PacifiCorp would obtain from wholesale sales (or power supply costs it would avoid) if retail sales were to decline. He tested this against the system average rate, against the residential average rate, and against the residential end-block rate to determine what would happen to PacifiCorp profits.

158. Mr. Lazar concluded that the 1 percent per year loss of sales postulated by Mr. Cavanagh would translate into an increase in profits of $6.8 to $12.8 million, even without the decoupling mechanism proposed by NRDC. With the $21 million decoupling adjustment proposed by NRDC, the mechanism would produce an increase of profits of $28 to $34 million under the assumed 1 percent per year sales decline. Exh. No. 691, p. 30 and Exh. No. 694.

159. The Commission Staff did not prepare an analysis of the proposed mechanism. The Company did not present an analysis of the proposed mechanism. Mr. Lazar's testimony was not rebutted by PacifiCorp, despite filing of rebuttal testimony by Ms. Omohundro that addressed decoupling. Mr. Lazar's analysis was not questioned during cross-examination by either PacifiCorp or by NRDC. It is uncontested on this record.

C. Decoupling Must Provide Consumer Benefits; This Proposal Does Not.

160. The consistent position of this Commission on any form of automatic adjustment clause is that there must be demonstrated benefits for ratepayers. Exh. No. 691, p. 18, citing U-81-41 and U-88-2363-P. Neither PacifiCorp nor NRDC have identified any demonstrated benefits for ratepayers that would result from implementation of this proposal.

161. One form of benefit would be a lower cost of capital, as testified to by Mr. Lazar. Exh. No. 691, p. 12, ll.9-11. Neither NRDC nor PacifiCorp has proposed an adjustment to reflect the shift of sales volume risk from shareholders to ratepayers. *Id.*, p. 13, ll. 1-2. Another form of benefit would be evidence that Pacific would do a better job on energy conservation.

162. The record shows that Pacific has been achieving its share of the regional conservation targets set by the Northwest Power Planning Council. Exh. No. 693. Ms. Steward testified: "I would note that the company is capturing the cost-effective DSM targets that were identified by the Northwest Power Plan in the Fifth Power Plan as well as their own IRP. TR. 1156. If promoting utility investment in conservation is the *raison d'ètre* for decoupling, there needs to be some evidence that the Company will respond to the mechanism. There is no such evidence in this case.

163. Commissioner Oshie probed this issue in detail at the hearing with Mr. Cavanagh:

> "And I know what your testimony has been, but I don't see anything offered up by either in your testimony or by the company saying that, if you implement decoupling, we will put, you know, $5 million on the table for energy efficiency programs or, you know, or $2 million or we'll, you know, increase our efforts to explore other cost-efficient, cost-effective efficiency tools, I don't see it."

TR. 1097:20-1098:2 .

ATTORNEY GENERAL OF WASHINGTON
Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012

In response, Mr. Cavanagh could point to no specific proposal or commitment. Instead, all he could offer the Commission was the suggestion that we wait and see at the end of the pilot whether this question had been answered. TR. 1098:8-20.

164. Ms. Omohundro was even more clear on behalf of PacifiCorp.

> Q. (By Chairman Sidran): I did hear you say, I believe, in response to Mr. Trotter's question, that there's no commitment in this docket on the part of the company to any particular investment, additional investment in the size of demand side management in the event that decoupling were adopted, correct?
>
> A. (By Ms. Omohundro): Correct. TR. 1146 (Omohundro).

In light of these statements, there is simply no basis to conclude that the decoupling proposal is in the public interest.

D. It Would Be A Practical Impossibility To Implement the NRDC Proposal In This Docket.

165. The NRDC proposal hinges on adoption by the Commission of a "fixed cost revenue requirement." Mr. Cavanagh testified that this cost recovery should be:

> The authorized fixed costs, so whatever the Commission determines in this case as an appropriate authorized revenue requirement associated with fixed costs should in my judgment be recovered independently of sales volumes.

TR. 1067.

Mr. Cavanagh then points to the analysis prepared as part of the Company's cost of service study, which he sponsored as Exh. No. 672. That study takes the production, transmission, and distribution costs which PacifiCorp's original testimony proposed be assigned to the various customer classes in Washington, and divides them into "fixed" and "variable" cost categories.

166. These calculations are the result of numerous preceding studies, including (but not limited to):

a) The interstate cost allocation study, which determines what fixed and variable production and transmission costs are assigned to the state of Washington; this is a highly contested element of this proceeding.

b) The cost of capital analysis, which determines what rate of return, should be applied to the investment in production, transmission, and distribution plant. This is a highly contested element of this proceeding.

c) The class cost of service study, which divides costs between customer classes, and would form the basis of the "revenue per customer" for the residential class and for the other classes, as NRDC has proposed. The parties in this proceeding entered into a stipulation on rate spread and rate design that specifically did not approve any particular approach to cost allocation between classes.

d) The weather normalization study, which adjusts test year sales to reflect normalized weather. This is a highly contested element of this proceeding. Staff and Pacific filed testimony on this issue, and ultimately reached an agreement on an adjustment for this proceeding, but no agreement on how to make such adjustments prospectively.

167. The bottom line is that there is absolutely no way to do the calculation that Mr. Cavanagh cites as the foundation of his proposal. The data does not exist today, and (because of the nature of the stipulations resolving issues in this case) will not exist at the conclusion of this proceeding. Furthermore, given the changes in all of these components, Mr. Cavanagh's reliance on prior cost of service parameters is of little use to the Commission in evaluating his proposal or implementing it.

168. Morever, no testimony in this proceeding sets forth the specific methodology for computing a "fixed cost revenue requirement." Public Counsel is not aware of and has been unable to find any Commission decision that includes a determination of this requirement. It is unclear what Mr. Cavanagh is referring to. What is clear is that the Commission must first resolve inter-jurisdictional cost allocation issues, double leverage issues, and class cost of service issues before it can take on the task of computing a "fixed cost revenue requirement" as proposed by Mr. Cavanagh.

E. No Analysis of the Proposal Was Offered by the Company.

169. The NRDC decoupling proposal fundamentally changes ratemaking, from a cost-based approach to one that ties revenues to the number of customers served. One would expect that such a significant change would be examined in detail by the Company prior to a decision of whether or not to endorse the proposal.

170. Public Counsel asked PacifiCorp what analysis it had prepared of the proposal. In Exh. No. 259, the Company stated that it had not prepared any analysis of the proposal.

171. The Company had an opportunity, in its rebuttal testimony, to contest Mr. Lazar's analysis, and to present an alternative analysis of the mechanism proposed by NRDC. It did not do so.

172. On cross-examination, PacifiCorp acknowledged it had not done an analysis.

> Q. (Mr. ffitch): Has the company prepared any analysis of the impact the proposed mechanism would have had if it had been in effect in the past?
>
> A. (Ms. Omohundro) We have not, and really that is why we are proposing to test the mechanism over a three year period.

TR. 1145.

173. The Bench asked Pacific to respond, in Bench Request No. 18, about the impact of the proposed mechanism. Once again, the Company prepared and submitted no analysis whatsoever. Perhaps the Company did not need to do any analysis because they had the opportunity to review Mr. Lazar's analysis, prepared with their own data. Mr. Lazar's analysis is uncontested on this record. It demonstrates that the proposed mechanism would increase PacifiCorp profits by $28 to $34 million over a five-year period under the assumption postulated by NRDC. Given that, it is no surprise that PacifiCorp is supporting the mechanism.

174. In light of the foregoing, it is unacceptable for the Company to suggest, as Ms. Omohundro has, that the analysis can wait until the mechanism is tested in a pilot. Mr. Lazar's testimony demonstrated that *without* any decoupling mechanism, the reduced sales posited by Cavanagh would lead to highly profitable surplus power sales generating excess profits of $6.8

to $12.8 million over 5 years. Mr. Cavanagh's proposal would add an additional $21 million of entirely unjustified profits. Ratepayers should not be asked to bear the cost of such an expensive experiment with no assurance that they will see any benefit and little advance planning or understanding of the proposal.

F. The NRDC Proposal is Not Well-Tailored to Washington.

175. The NRDC proposal had its genesis in California, where conditions are much different from PacifiCorp's service territory in Washington. First, PacifiCorp is a low-cost system, with average retail rates of around $.05/kWh. Exh. No. 691, p. 22, l. 24 (citing Griffith Table A). PacifiCorp projects that the wholesale market is expected to remain above its current rates for the next five years. *Id.,* p. 23.

176. Pacific Gas and Electric Company, in contrast, charges up to $.33 per kWh for residential electricity. TR. 1080. Mr. Cavanagh readily agreed that it is much more likely that the wholesale market could recover the lost retail revenues for PacifiCorp, and that the wholesale market would be "nowhere close" to the rates collected by Pacific Gas and Electric. TR. 1082.

177. Mr. Lazar's analysis was based upon PacifiCorp rates, and PacifiCorp's estimate of future wholesale market prices. These are shown on page 23 of his testimony, and it is quite clear that the wholesale market prices are forecast to be higher than PacifiCorp' retail rates for the next five years. The graphic in the testimony supports the analysis by Mr. Lazar that if PacifiCorp loses retail sales to conservation, it can sell the freed-up power at wholesale rates that will generate more revenue than its retail rates.

178. This is simply a natural result of PacifiCorp having a relatively low-cost generation system, and a relatively slow-growth customer base. It has not needed to add many new, expensive power plants, and so its average costs are well below the marginal costs faced by the region. PacifiCorp does not have a "margin" in retail rates over wholesale prices like California does. There are a different set of circumstances here than in California, and the solution that may work in California will be counterproductive in Washington.

G. Decoupling and Financial Risk.

179. Mr. Lazar testified that a risk-reducing measure like decoupling would allow for a reduction in the equity capitalization ratio of a utility. He cited an evaluation of the Northwest Natural Gas decoupling mechanism prepared for the Oregon Public Utility Commission and a report by Moody's in support of this. Exh. No. 691, p. 18. He further calculated that this risk mitigation would justify about a $1 million per year reduction in rates, due to the lower equity capitalization ratio. Exh. No. 691, p. 21 and Exh. No. 692.

180. Mr. Cavanagh dismissed this, without any analysis, stating that "no commission to my knowledge adopting the decoupling mechanism has ever coupled it to a reduction in authorized return…" TR. 1112. When asked by Commissioner Oshie if someone has "pulled together the research and evaluation" from the other states, Mr. Cavanagh changed the subject away from the formal evaluation reports that are available. TR. 1108.

H. Decoupling and Weather Adjustment.

181. In response to a question from Commissioner Sidran, Mr. Cavanagh readily agreed that weather risk was substantial, and could significantly change sales volumes. TR. 1113. He testified that under his proposed mechanism, the weather risk would remain with the Company – it would not be included in the decoupling mechanism. However, he provided no indication whatever of how the Commission would separate sales volume changes due to weather from those due to conservation programs. He simply stated that the Commission would use the "existing weather normalization methodology." TR. 1127.

182. Perhaps Mr. Cavanagh was unaware that weather normalization was a contested issue in this proceeding, with approximately $4.5 million separating the Staff witness (Mr. Mariam) from the Company. Public Counsel understands that this issue was settled between the parties with an agreement on a dollar amount for this proceeding, but no agreement on a methodology going forward. Once again, the NRDC proposal is vague when it comes time to actually define how it would be implemented.

I. Decoupling and PCA.

183. Both Mr. Cavanagh and Ms. Omohundro testified that the proposed decoupling mechanism was compatible with the PCA. TR. 1102:3-20 (Cavanagh); TR. 1141:16-18 (Ohohundro). However, this is also unsupported by any analysis or substantial evidence showing how they would work together.

184. Mr. Cavanagh testified that his proposal was "a full decoupling mechanism that I am proposing comparable to California." TR. 1076. Interestingly enough, the Company's chief policy witness testified that such a mechanism would be unacceptable to PacifiCorp:

> For instance, adoption of a full decoupling mechanism like California's would be inconsistent with the PCAM we are proposing in this proceeding, in two respects. First, the decoupling mechanism would duplicate a base rate recovery adjustment which is already included in the PCAM we are proposing. Second, the 90/10 sharing mechanism proposed in the PCAM is inconsistent with "100 percent" decoupling.

Exh. No. 1, p. 24, ll. 10-15 (Furman).

IX. RATE SPREAD AND RATE DESIGN

185. Staff, ICNU, and Public Counsel filed the Joint Testimony of Joelle Steward, Kathryn Iverson, and Jim Lazar, containing their common recommendations on the issues of rate spread and rate design in the event that any rate change is approved in this docket. Exh. No. 711. PacifiCorp has accepted the recommendations. Exh. No. 257, p. 3, ll. 4-9 (Griffith).

A. Rate Spread.

186. The Company initially proposed allocating any revenue increase on an equal percentage basis to all customer classes except General Service Schedules 24 and 36 which would receive 75 percent of the average increase to more accurately reflect the cost of service. Exh. No. 711, p. 4, ll.3-8. The joint testimony agreed with respect to Schedule 24, but as to Schedule 36, recommended that the schedule receive the average percentage increase. All other schedules would receive a uniform percentage capturing the residual revenue requirement --- approximately 106 percent of the average increase. *Id.*, p. 5, ll.1-2.

187. The joint recommendation is based primarily on application of the principle of parity. Based on a parity analysis, *Id.*, pp. 6-9, the testimony recommends a result that makes gradual movement towards parity. *Id.*, p. 8.

188. In the event that rate decreases are ordered, the recommendation is, for simplicity, to apply the decrease equally across customer classes. *Id.*, p. 9, ll.7-8.

B. Rate Design.

189. The joint testimony recommends that the Commission adopt the rate design proposed by PacifiCorp, with all billing components adjusted (up or down) proportionally in the manner proposed by the Company to reflect the approved revenue requirement. *Id.*, p. 10.

X. CONCLUSION

190. For the reasons set forth above, Public Counsel respectfully requests that the Commission accept and adopt the Public Counsel recommendations for resolving the important issues presented in this docket.

DATED this 27th day of February.

ROB McKENNA
Attorney General

Simon J. ffitch
Assistant Attorney General
Public Counsel

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ATTORNEY GENERAL OF WASHINGTON
Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012

ATTORNEY GENERAL OF WASHINGTON
Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012

ATTORNEY GENERAL OF WASHINGTON
Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012

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ATTORNEY GENERAL OF WASHINGTON
Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012

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ATTORNEY GENERAL OF WASHINGTON
Public Counsel
900 4th Ave., Suite 2000
Seattle, WA 98164-1012