WUTC DOCKET: UE-230172 & UE-210852
EXHIBIT: MDM-13X
ADMIT ☑ W/D ☐ REJECT ☐

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP, d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET UE-230172 *(Consolidated)*
In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS' Petition for Order Approving Deferral of Increased Fly Ash Revenues	DOCKET UE-210852 *(Consolidated)*

CROSS-EXAMINATION EXHIBIT
OF MATTHEW MCVEE

ON BEHALF OF
SIERRA CLUB

EXHIBIT MDM-__X
ORDER 05, UE-130043 (DEC. 4, 2013)

December 4, 2023

[Service Date December 4, 2013]

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	DOCKET UE-130043
	)	
Complainant,	)	ORDER 05
	)	
v.	)	FINAL ORDER REJECTING TARIFF SHEETS; RESOLVING CONTESTED ISSUES; AUTHORIZING AND REQUIRING COMPLIANCE FILING
	)	
PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY,	)	
	)	
Respondent.	)	
. . . .	)	

***Synopsis**: The Commission rejects revised tariff sheets PacifiCorp filed on January 11, 2013, that would have increased rates by approximately 14.1 percent, raising $42.8 million in additional revenue for the Company, if approved by the Commission. The Commission, however, authorizes and requires PacifiCorp to file revised tariff sheets stating rates that will recover approximately $16.7 million (5.5 percent) in additional revenue, an increase that the Commission finds to be reasonable based on the record in this proceeding.*

The Commission rejects PacifiCorp's and other parties' proposed revisions to the West Control Area inter-jurisdictional cost allocation methodology, authorized in Docket UE-061546 in June 2007.[1] This means, among other things, that the cost of Qualifying Facilities under the Public Utilities Regulatory Policies Act (PURPA)[2] will continue to be allocated to the states in which such facilities are located. The

[1] *WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817 (consolidated), Order 08 (June 21, 2007). The Commission approves one change in the WCA inter-jurisdictional allocation of power costs based on a change in transmission capacity, as agreed between the Company and Commission Regulatory Staff.

[2] Pub.L. 95–617, 92 Stat. 3117 (enacted November 9, 1978).

Commission approves various additions to rate base, including the pro forma costs of certain production related facilities with post-test period in-service dates.

The rates determined in this Order to be fair, just, reasonable, and sufficient are based on a capital structure of 49.10 percent equity,50.62 percent debt, and 0.28 percent preferred stock, with a 9.5 percent return on equity, a 5.29 percent cost of debt, and a 5.43 cost of preferred stock. This results in an overall rate of return of 7.36 percent.

The Commission rejects PacifiCorp's proposed Power Cost Adjustment Mechanism (PCAM) based on the Company's failure to demonstrate need for a PCAM, and because the proposed mechanism is not designed in accordance with clear direction from the Commission concerning the required elements for a PCAM.

The Commission approves the parties' settlement of cost of service, rate spread and rate design providing that the revenue and rate increases approved in this Order will be spread to all rate schedules, other than street lighting, on an equal percentage basis.

Finally, the Commission approves an 18 percent increase in funding for PacifiCorp's Low Income Bill Assistance Program, increasing the benefit per participant by 11 percent. This increase is consistent with the requirements of the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012.[3]

[3] *See WUTC v. PacifiCorp*, Docket UE-111190, Order 07 ¶¶ 17-18 and 40-44 (March 30, 2012).

TABLE OF CONTENTS

SUMMARY

1 **PROCEEDING:** PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp) filed this general rate case proceeding with the Washington Utilities and Transportation Commission (Commission) on January 11, 2013. Following public comment hearings in Yakima on July 15, 2013, and in Walla Walla on July 16, 2013, and evidentiary hearings in Olympia on August 26 – 28, 2013, the parties filed Initial Briefs and Reply Briefs on October 1 and 11, 2013, respectively. This Final Order resolves all disputed issues in this proceeding.

2 **PARTY REPRESENTATIVES:** Katherine McDowell, McDowell Rackner & Gibson PC, Portland, Oregon, represents PacifiCorp. Robert D. Cedarbaum, Senior Assistant Attorney General, Olympia, represents the Commission Staff. Lisa Gafken, Assistant Attorney General, Seattle, represents the Public Counsel Section of the Washington Office of Attorney General (Public Counsel).

3 Melinda J. Davison and Joshua D. Weber, Davison Van Cleve, Portland, Oregon, represent the Boise White Paper, L.L.C. (Boise). Brad Purdy, attorney at law, Boise, Idaho, represents the Energy Project.[4]

4 **COMMISSION DETERMINATIONS**: The Commission suspended and set for hearing the rates PacifiCorp originally proposed in its filing on January 11, 2013. Based on the record of this proceeding we find that neither the Company's as-filed rates, nor the revised rate requests PacifiCorp made through its rebuttal filing and at the conclusion of the advocacy phase, are fair, just and reasonable. On the other hand, we also find that PacifiCorp's current rates are insufficient. It therefore falls to us to determine fair, just, reasonable and sufficient rates based on the record.[5]

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[4] The Columbia Rural Electric Association (CREA), represented by Irion Sanger, Davison Van Cleve, Portland, Oregon was granted leave to intervene in this proceeding under the "participation in the public interest" standard in WAC 480-07-355(3) in connection with a single issue that later was withdrawn from the case. In its order granting PacifiCorp leave to withdraw the issue, the Commission dismissed CREA as an intervenor as provided in WAC 480-07-355(4).

[5] RCW 80.28.020.

5 We find a revenue deficiency of $16,702,420 for PacifiCorp's electric service provided in Washington. We authorize PacifiCorp to file rates to recover additional revenue in accordance with our decisions in this Order. When thus implemented in compliance with the terms and requirements of this Order, PacifiCorp's resulting rates will be fair, just, reasonable and sufficient, and neither unduly discriminatory nor preferential. The Company's new rates will be effective no earlier than December 10, 2013.

6 Among other significant findings and conclusions, we determine that PacifiCorp's capital structure should include a 49.10 percent equity ratio, balanced with a 50.62 percent debt ratio and 0.28 percent preferred stock. In terms of capital costs, we set PacifiCorp's authorized rate of return on equity at 9.50 percent, determined within a range of reasonableness demonstrated by the cost-of-capital expert witnesses' testimony to be between 9.00 percent and 9.70 percent. These determinations, coupled with PacifiCorp's actual debt and preferred stock costs, result in an overall rate of return of 7.36 percent.

7 We conclude that PacifiCorp failed to carry its burden to show that revisions to the West Control Area inter-jurisdictional cost allocation methodology embedded in its initial filing are appropriate to make. We accordingly reject the proposed revisions and require the Company to rerun its revenue requirements study for purposes of its compliance filing using the previously approved WCA methodology, with one exception justified by a change in transmission capacity from the Jim Bridger coal plant in Wyoming.

8 We approve and adopt the parties' settlement of issues related to cost of service, rate spread and rate design. We also approve uncontested increases in funding for the Company's low-income bill assistance program.

9 We reject PacifiCorp's proposed Power Cost Adjustment Mechanism (PCAM). The Company failed to demonstrate sufficient power cost variability to warrant approval of such a mechanism. Moreover, the Company's proposal fails to include design elements the Commission previously has directed PacifiCorp to include in any PCAM proposal.

MEMORANDUM

I. Background and Procedural History

10 On January 11, 2013, PacifiCorp filed revised tariff sheets with the Commission to increase rates and charges for electric service provided to customers in the state of Washington. The Company initially requested an electric rate increase of $42.8 million, or 14.1 percent. The Commission suspended operation of the as-filed tariffs by Order 01 entered in this docket on January 24, 2013. PacifiCorp later revised its request to approximately $37 million or 12.2 percent.

11 The Commission convened a prehearing conference at Olympia on February 13, 2013. The Commission held public comment hearings in Yakima on July 15, 2013, and in Walla Walla on July 16, 2013. On various dates established in its procedural schedule, the Commission accepted prefiled testimony and exhibits from the Company, the Commission's regulatory staff (Commission Staff or Staff),[6] and other parties. The Commission held evidentiary hearings in Olympia on August 26 – 28, 2013, to receive evidence from the parties and to allow them an opportunity to conduct cross-examination of witnesses who prefiled testimony. These hearings also gave the Commission an opportunity to conduct inquiry from the bench.

12 During the public comment hearings, the Commission received into the record oral comments and exhibits from 12 members of the public.[7] The Commission also accepted numerous written comments from members of the public. The final transcript in this proceeding includes 589 pages and reflects the admission of prefiled testimony and exhibits sponsored by 34 witnesses. The documentary record includes 286 exhibits. The fully developed record, including public comment and detailed evidence concerning PacifiCorp's revenue requirements and other issues, was closed

[6] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

[7] The Commission also received numerous written comments from members of the public. These comments are identified in the formal record as Exhibit B-1.

on November 8, 2013, following receipt of several responses to Commission bench requests made during and after the hearing.

13 The parties filed their Initial Briefs on October 1, 2013, and Reply Briefs on October 11, 2013. We have considered the parties' arguments and reviewed the full record in this proceeding. Our discussion and determination of the issues follows below.

II. Discussion and Decisions

A. Introduction

14 The Commission's responsibility in general rate case proceedings is to determine an appropriate balance between the needs of the public to have safe and reliable electric services at reasonable rates, and the financial ability of the utility to provide such services on an ongoing basis. Table 1 illustrates that the parties in this proceeding hold very different ideas of what amount of revenue increase strikes this balance.

TABLE 1
Proposed Total Adjustments to Annual Revenue Requirement

	As-Filed	Response	Rebuttal/Cross	Per Briefs
PACIFICORP	$42,800,673 (14.1%)		$36,933,863 (12.1%)	
Staff		$14,619,641 (4.8%)		$13,601,556 (4.5%)
Public Counsel		$19,815,120 (6.5%)[8]		
Boise White Paper		$10,832,078 (3.6%)		

The range of possible outcomes undoubtedly encompasses a somewhat narrower range of reasonable outcomes. We must determine solely on the record of this

[8] Public Counsel endorses additional adjustments proposed by other parties (*e.g.*, addressing cost of capital), further reducing the amount it advocates should be approved.

proceeding what rates within the reasonable range are fair to both the Company and its customers.

15 We must determine on the basis of the evidence presented what levels of prudently incurred expenses the Company will experience prospectively, and allow for recovery of those expenses. In addition, we must determine the Company's "rate base" and allow for an appropriate rate of return on that rate base.[9] This is necessary to allow the Company to recover the costs of its investments in infrastructure, repay its lenders, and provide an opportunity for the Company to earn a reasonable return, or profit, some of which may be distributed to its equity investors in the form of stock dividends. The sum of the two figures – expenses and return on rate base – constitutes the company's revenue requirement that we approve for recovery in rates.[10] The Washington Supreme Court explained this rate-making formula as follows:

> In order to control aggregate revenue and set maximum rates, regulatory commissions such as the WUTC commonly use and apply the following equation:
>
> $$R = O + B(r)$$
>
> In this equation,
>
> > R is the utility's allowed revenue requirements;
> > O is its operating expenses;
> > B is its rate base; and
> > r is the rate of return allowed on its rate base.
>
> Although regulatory agencies, courts and text writers may vary these symbols and notations somewhat, this basic equation is the one which has evolved over the past century of public utility regulation in this country and is the one commonly accepted and used.[11]

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[9] Reduced to a simple definition, rate base is the Commission-approved level of PSE's investment in facilities plus the cash, or "working capital" supplied by investors that is used to fund the Company's day-to-day operations. The Commission follows the original cost less depreciation method when determining the value of a utility's property that is used and useful in providing service to customers. *People's Organization for Washington Energy Resources v. Washington Utilities & Transportation Comm'n*, 104 Wn.2d 798, 828, 711 P.2d 319 (1985).

[10] *See id.* at 807-09 (describing ratemaking principles and process).

[11] *Id.* at 809.

16 In this case, there are a host of contested issues concerning operating expenses, rate base and rate of return. We discuss and resolve each of these issues below, arriving ultimately at revenue requirements to be recovered prospectively by PacifiCorp in its electric rates.

17 We begin our discussion of the contested issues with the topics of capital structure and costs of capital. We resolve disputes over the appropriate levels of equity and debt to include in the Company's capital structure, and disputes concerning rates of return for equity and debt to apply when determining the overall authorized cost of capital. This key outcome, the overall rate of return, is a principal driving factor in determining PacifiCorp's revenue requirements for electric service. This, in turn, significantly affects the level of rates customers will pay.

18 Following our determinations of PacifiCorp's allowed capital structure and capital costs, we discuss and resolve the parties' disputes over what adjustments should be authorized for various operating expenses and rate base items, and how certain of these should be accounted for in setting rates. The Company proposes a significant number of adjustments. Many of these are uncontested, but there are disputes that we must resolve concerning others.

19 PacifiCorp does business in six western states. In the Company's rate cases there are questions about how costs and revenues should be allocated among the various jurisdictions. This Commission approved and has used for a number of years the so-called West Control Area (WCA) inter-jurisdictional cost allocation methodology to determine rates in Washington.[12] PacifiCorp filed this case with certain unilateral modifications to the WCA method that resulted in a number of contested issues regarding inter-jurisdictional cost allocation. One very significant operating expense affected by this issue is the Company's net power costs. The parties disagree concerning what level of power costs customer should have to pay and disagree over PacifiCorp's proposal for a power cost adjustment mechanism (PCAM).

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[12] *WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817 (consolidated), Order 08, ¶¶ 43-58 (June 21, 2007). The WCA methodology recognizes that PacifiCorp includes two control areas with limited transmission capacity between them. PacifiCorp's west balancing authority area or west control area (PWCA) includes Oregon and California, in addition to Washington. PacifiCorp's east balancing authority area or east control area (PACE) includes Idaho, Utah, and Wyoming.

20 In addition, we are called upon in this case to resolve disputed issues concerning whether certain post-test period capital investments should be included for recovery in rates. These issues concern both rate base, on which the Company is entitled to earn a return, and operating expenses. Additional contested issues concern general wage increases and executive compensation, and investor-supplied working capital, the latter of which is used, among other things, to fund PacifiCorp's day-to-day operations. We discuss and resolve each of these issues below, arriving ultimately at revenue requirement to be recovered prospectively by PacifiCorp in its electric rates.

21 Taking the last step to determine the specific rates various types of customers will pay, we address rate spread and rate design. In doing so, we establish how PacifiCorp's costs will be allocated to different classes of customers, such as residential, commercial and industrial, and the means by which those costs will be recovered from each customer class in base rates and rates tied to levels of use. We address, too, the Company's programs that are designed to assist low-income customers that PacifiCorp serves in Washington. The parties propose to resolve these matters on the basis of settlement terms to which they agreed during the course of this proceeding and in a prior case, as we discuss below.

B. Capital Structure and Cost of Capital

22 Large electric utilities typically finance their operations using a combination of equity, long-term and short-term debt. These three sources of capital each have carrying costs. Equity investment typically is the highest cost source of capital because it is unsecured by assets of the utility, and has historically required a premium related to its relative risk. In contrast to equity return, long-term debt receives a return that is secured in contract by the company's assets. Thus, long-term debt entails less risk for investors and is the second highest cost of capital, expressed as an interest rate demanded by lending institutions and bond holders. Short-term debt typically is the lowest cost form of capital and the smallest component of the capital structure since utility assets are generally depreciated over a long period of time and require long-term financing. It nevertheless can be an important part of a company's capitalization, providing financing for shorter term obligations or as bridge capital used when acquiring longer-lived assets.

23 Some companies, including PacifiCorp, use preferred stock as a source of capital. Such stock has characteristics of both debt (*e.g.,* fixed dividends) and equity (*e.g.,* potential appreciation). Preferred stock has a higher claim on the assets and earnings of a company than common stock and generally has a dividend that must be paid out before dividends to common stockholders. The carrying costs of preferred stock are generally in the range of the cost of long-term debt.

24 Capital markets are constantly changing and are influenced greatly by a complex mix of monetary and fiscal policies. A company must use good judgment in determining the appropriate mix of capital elements to employ in its capital structure, and when to access the capital markets. Senior management must constantly assess conditions in capital markets, in consultation with the Board of Directors and seek to optimize the Company's capital structure, balancing risk and economy.

25 For regulated utilities, ratepayer interests must also be a major consideration when determining an appropriate capital structure for the Company in setting rates.[13] Capital structure, and particularly the cost of equity ratio, materially impacts the price customers pay for service. Due to the relative difference between the cost of equity and the cost of debt, a capital structure with relatively more debt and less equity may result in a lower overall cost of capital.[14] This results in lower rates for customers. This is commonly referred to as "economy." On the other hand, a capital structure with relatively more equity and less debt may result in a higher overall cost of capital and higher rates for customers, but enhanced financial integrity. This is commonly referred to as "safety."[15]

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[13] The Company's officers and directors, of course, are cognizant that their business is one "clothed with a public interest" because it is devoted to uses in which the public has an interest (*i.e.*, the delivery of commodities considered essential to modern life) and, hence, is subject to public control, the face of which is the Commission, as empowered by the legislature.

[14] The use of equity versus debt capital is also significant because of the impact of federal income taxes in the determination of a utility's revenue requirement. The additional revenue necessary to pay a higher return on equity must be supported by additional revenue from customers to pay Federal income taxes. On the other hand, when financing with debt the utility can deduct its interest expense resulting in a reduction in the utility's costs and revenue requirement, benefiting both customers and the utility.

[15] This simplified relationship assumes that the cost of equity does not vary with the equity ratio. In fact, the cost of equity may decline as the equity ratio increases because financial risk declines. *See* 1 Leonard Saul Goodman, *The Process of Ratemaking* 642-43 (1998).

26 The Commission must address this basic tension between economy and safety in determining the capital structure to use for setting a utility's rates. This tension manifests in the context of a contested case such as this one in the form of evidence provided by expert witnesses who recommend a range of results.[16] The Commission carefully reviews this evidence and seeks the appropriate balance as it sets rates. A company's weighted cost of capital, or overall rate of return (ROR), is determined by multiplying the relative amount of each component (*i.e.*, equity, long-term debt , short-term debt, and preferred stock) in the capital structure by each component cost, and then summing the results.[17]

27 The parties typically disagree regarding the appropriate cost of equity and may disagree concerning debt costs. Based on the parties' evidence, the Commission establishes a reasonable range for allowed equity return vis-à-vis what would be expected for businesses of comparable risk. Once a reasonable range is determined, the Commission considers additional factors affecting the balance between maintenance of the Company's financial integrity and strength, and cost to ratepayers. Debt costs are usually readily observable based on the known costs of the Company's long-term and short-term debt instruments. If these costs are disputed, the Commission again determines on the basis of the evidence presented the level of debt costs it will authorize.

28 In this case, PacifiCorp included testimony on the subject of cost of capital from two witnesses, Mr. Bruce N. Williams, PacifiCorp's Treasurer, and Dr. Samuel C. Hadaway, a consultant, recommending respectively Commission adoption of the Company's preferred capital structure and costs of capital. Mr. Williams recommends an increase in PacifiCorp's currently authorized equity level in the Company's capital structure from 49.1 percent to 52.22 percent.[18] He proposes a corresponding reduction in long-term debt from 50.60 percent to 47.50 percent and a

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[16] The Company witnesses typically offer testimony that defines the high end of the range in terms of equity ratio and return on equity while Commission Staff, Public Counsel or intervenor witnesses typically present testimony that recommends less equity in the capital structure and a lower return on equity.

[17] *See infra.*, Table 7, which shows these calculations using the factors determined by the Commission in this case.

[18] Williams, Exh. No. BNW-14T at 5:1-7.

slight reduction in preferred stock from .30 percent to .28 percent. PacifiCorp's currently approved capital structure includes no short-term debt and the Company proposes to maintain the status quo in this regard.

29 Dr. Hadaway recommends an increase in PacifiCorp's authorized return on equity from the level of 9.8 percent determined in the Company's most recent contested general rate proceeding, completed in March 2011,[19] to 10.0 percent. He testifies this is at the high end of a range of 9.4 percent to 10.0 percent, which he initially determined using the discounted cash flow (DCF) methodology. Dr. Hadaway proposes the same 10.0 percent return on equity in his rebuttal testimony, but relies on a risk premium analysis rather than DCF modeling to support his recommendation. Mr. Williams proposes to use the Company's actual long-term debt costs, which he updated on rebuttal to 5.29 percent, from the as-filed level of 5.37 percent.

30 The effect of the Company's overall proposals for its equity ratio and return, coupled with its updated debt structure and costs, is portrayed in Table 2.

TABLE 2
PacifiCorp's Proposed Overall Cost of Capital

Component	Percent of Total	Cost	Weighted Average
Equity	52.22%	10.00%	5.22%
Long-Term Debt	47.50%	5.29%	2.51%
Preferred Stock	0.28%	5.48%	0.02%
Total	100.00%		7.75%

31 Two other parties, Commission Staff and Boise White Paper, offer testimony and exhibits on the subject of cost of capital. Mr. Elgin testifies for Staff, proposing less equity in the capital structure and a lower rate of return on equity. He also proposes the imputation of short term debt, which he rolls into an overall debt component share

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[19] *WUTC v. PacifiCorp,* Docket UE-100749, Order 06 (March 25, 2011). The Commission subsequently resolved a PacifiCorp general rate case filing by approving a settlement agreement that does not address return on equity. Notably, however, the Company's filing included, and the settlement reflects, an adjustment to the Company's debt costs that lowered its overall rate of return from the 7.81 percent approved in Docket UE-100749 to 7.74 percent. *WUTC v. PacifiCorp,* Docket UE-111190, Order 07 (March 30, 2012) (Attachment-Settlement Stipulation ¶ 21).

and cost. The effect of this is to increase the amount of debt in the Company's capital structure and to slightly reduce cost of debt relative to what PacifiCorp originally proposed. However, Staff's proposed cost of debt ultimately ended up being higher than what the Company now proposes. Staff's full proposal for capital structure and cost of capital is shown in Table 3.

TABLE 3
Staff's Proposed Overall Cost of Capital

Component	Percent of Total	Cost	Weighted Average
Equity	46.00%	9.00%	4.14%
Debt	53.72%*	5.34%*	2.87%
Preferred Stock	0.28%	5.43%	0.02%
Total	100.00%		7.03%

* Debt ratio includes 4.0 percent imputed short term debt. Debt cost is a blended rate based on Avista's overall cost of debt approved in Dockets UE-120436 and UG-120437.[20]

32 Mr. Gorman testifies for Boise White Paper. He recommends that the Commission make no change to the Company's currently approved capital structure.[21] He would, however, reduce PacifiCorp's equity return to 9.20 percent while accepting the Company's other cost of capital rate components. Boise White Paper's proposal for capital structure and cost of capital is shown in Table 4.

[20] *WUTC v. Avista,* Dockets UE-120436 and UG-120437 (consolidated), Order 09, Appendix A – Multiparty Settlement ¶ 7 (December 26, 2012).

[21] Mr. Gorman agrees with the Company's slight reduction to the preferred stock ratio from .30 percent to .28 percent. He adds the .02 percent difference to the debt component.

TABLE 4 Boise White Paper's Proposed Overall Cost of Capital			
Component	**Percent of Total**	**Cost**	**Weighted Average**
Equity	49.10%	9.20%	4.52%
Long-Term Debt	50.62%	5.29%	2.67%
Preferred Stock	0.28%	5.48%	0.02%
Total	100.00%		7.21%

33 Table 5 summarizes the capital structure and cost rates from PacifiCorp's most recent contested general rate case and the recommendations of the Company, Staff and Boise White Paper at the close of the record in this case.

TABLE 5 Capital Structure and Cost of Capital Proposals								
	Commission Approved		**Company Proposal**		**Staff Proposal**		**Boise White Paper Proposal**	
	Share/Cost		**Share/Cost**		**Share/Cost**		**Share/Cost**	
Equity	49.10	9.8	52.22	10.00	46.00	9.00	49.10	9.20
Long-Term Debt	50.60	5.89	47.50	5.29	53.72	5.34	50.62	5.29
Preferred Stock	0.30	5.41	0.28	5.43	0.28	5.43	0.28	5.43
OVERALL ROR	**7.81**		**7.75**		**7.03**		**7.25**	

1. Capital Structure

34 Table 5 shows, among other things, the significant variation in the parties' respective capital structure recommendations, including equity ratio proposals that range from PacifiCorp's 52.2 percent ratio at the high end to Staff's 46.0 percent ratio at the low end. Boise White Paper is almost squarely in the middle of this range, advocating no change from the currently approved 49.10 percent equity ratio.

35 PacifiCorp presents its case on capital structure through its Treasurer, Bruce Williams. Mr. Williams testifies that:

> The Company used an average of the five-quarter ends spanning the 12 months ending June 30, 2013, to calculate its proposed capital structure. This approach smoothes volatility in the capital structure, which will fluctuate as the Company expends capital, issues or retires debt, retains earnings, or declares dividends.[22]

Mr. Williams testifies further that the equity ratio is consistent with the Company's actual equity levels since the end of 2011.[23] According to Mr. Williams, this equity level is necessary to maintain the Company's credit rating and ensure continued access to low-cost capital, particularly during a period of significant capital expenditures.[24]

36 Staff does not dispute Mr. William's portrayal of PacifiCorp's actual capital structure. Staff argues, however, that the Commission should continue to use a hypothetical capital structure in order to ensure the Company's capital structure properly balances safety against economy.[25] Mr. Elgin argues this is particularly important because PacifiCorp is privately held by MidAmerican Energy Holdings Company (MEHC), which controls the Company's capital structure to favor its owner. Staff backs up its claim that MEHC's incentive is to enhance its returns by capitalizing PacifiCorp with too much equity rather than short-term debt by pointing to the growth in the Company's equity since its acquisition by MEHC eight years ago.[26] Since it was acquired by MEHC, PacifiCorp's actual equity ratio has grown from 46.4 percent in 2005 to 52.4 percent in 2012.[27]

37 The growth in PacifiCorp's equity capitalization is largely the result of cash infusions from MEHC. Staff notes that when MEHC acquired PacifiCorp it committed that

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[22] Williams, Exh. No. BNW-1T at 12:12-19.

[23] *Id.* 14:1-9.

[24] *Id.* 3:9-14, 13:7-13; Williams, TR. 221:15-23.

[25] Staff Initial Brief ¶¶ 18-19.

[26] *See id.* ¶ 20.

[27] *Id.* (citing Williams, Exh. No. BNW-18CX at 1 and 7).

ratepayers would not be harmed by paying a higher cost of capital as a result of the sale.[28] Yet, Staff argues, this is exactly what PacifiCorp advocates now, as it previously advocated in the Company's 2010/2011 general rate case.[29] In the earlier case, the Commission described the growth in PacifiCorp's equity capitalization from 46 percent to 52.1 percent as "a remarkable level of growth in three years."[30] The Commission rejected PacifiCorp's proposal that its actual capital structure be used to set rates and accepted Mr. Gorman's hypothetical equity ratio of 49.1 percent, finding it to be more consistent with ratepayers' interest in a capital structure that reflects economy.[31]

38 PacifiCorp argues that adoption of the Company's actual equity ratio will provide it a better opportunity to earn its authorized overall rate of return. The Commission has adjusted equity share for this purpose in some cases. However, in the Puget Sound Energy case PacifiCorp cites in support of this argument, the adjustment was from a relatively modest 46 percent ratio to a still reasonable 48 percent ratio. PacifiCorp's argument ignores that, at 49.1 percent, its approved equity ratio is already high relative to the utility to which it compares itself. Increasing equity in the capital structure is a tool the Commission can use in its discretion to address alleged chronic under earning by a utility. This does not mean it is justified in every case.

39 *Commission Determination:* We determine that PacifiCorp's currently approved capital structure appropriately balances safety and economy, and should be used for setting rates in this case. In other words, the Company's approved capital structure should continue to include the equity, debt and preferred stock shares the Commission approved in Docket UE-100749 in 2011[32] and again in Docket UE-111190 in 2012.[33]

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[28] *In re Application of MidAmerican Energy Holdings & PacifiCorp*, Docket UE-051090, Order 07 (February 22, 2006). (Appendix A, Commitment 21: "MEHC and PacifiCorp will not advocate for a higher cost of capital as compared to what PacifiCorp's cost of capital would have been, using Commission standards, absent MEHC ownership.").

[29] *See generally WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶¶ 21-43 (Mar. 25, 2011).

[30] *Id.* ¶ 40.

[31] *Id.*

[32] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶¶ 40 and 43 (Mar. 25, 2011). PacifiCorp's evidence and advocacy in this earlier case are strikingly similar to what it advances here. In Docket UE-100749 PacifiCorp proposed a capital structure of 52.1 percent common equity, 0.3 percent preferred stock, and 47.6 percent long-term debt. This was "based on an

The record in this case demonstrates that this capital structure will continue to support PacifiCorp's current credit rating, and provide sufficient cash flows to support the financial metrics analyzed by the credit rating agencies. Indeed, during the pendency of this case PacifiCorp obtained capital that reduced its cost of long-term debt from 5.37 percent to 5.29 percent.[34] This tangibly demonstrates that the Company has sufficient access to low-cost capital.

40 Having noted above the similarity between PacifiCorp's evidence and advocacy in its 2010/2011 general rate case and the case here, it is worth observing further that *all* of the cost of capital evidence and advocacy in this case closely matches that presented in the earlier case. In terms of balancing safety and economy, we again conclude that the Company's proposed capital structure contains too much equity, which tips the balance too far in favor of investor interests over those of ratepayers.[35] We conclude that Staff's proposed 46.0 percent equity in this case is too low and would tip the scales too far toward economy relative to the Company's financial needs. In the 2010/2011 case the Commission determined that PacifiCorp's equity share should be increased above the 46 percent that had been previously approved in the Company's 2006/2007 general rate case.[36] We find no compelling basis in the record here supporting a return to the lower equity ratio that Staff advocates.

41 Finally, we conclude again in this case that Mr. Gorman's proposed capital structure including a 49.1 percent equity ratio (*i.e.,* the status quo) best reflects what is appropriate for this Company. This capital structure has proven over several years to be well-balanced in terms of safety and economy. While we continue to be concerned about PacifiCorp's relatively spare and infrequent use of the lowest cost form of capital, short-term debt, setting PacifiCorp's equity share for regulatory purposes at a level lower than what Company management and owners presently maintain in equity

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average of five-quarters, ending December 31, 2010, which the Company argued smoothes volatility caused by expending capital, issuing and retiring debt, and the retention of earnings and infusion of equity." Order 06 ¶ 23 (citing Williams, Exh. No. BNW-1T at 3). Mr. Williams' testimony in this case is essentially identical. *See supra* ¶ 39.

[33] *WUTC v. PacifiCorp*, Docket UE-111190, Order 07 (February 21, 2012).

[34] Williams, Exh. No. BNW-14T 5:4-5.

[35] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 39 (March 25, 2011).

[36] *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶ 222 (June 21, 2007).

share for financial purposes results in a lower overall cost of capital. This is consistent with the result that would follow were we to impute directly 3 to 5 percent short-term debt, as Staff recommends. As the Commission said in its final order in Docket UE-100749: "our adoption of a 49.1 percent equity ratio already ameliorates the potential adverse effects of the Company's proposed capital structure that we judged to contain an excessive equity component."[37]

42 In summary, adjusting only to account for a slight reduction in PacifiCorp's preferred stock ratio, we again approve a hypothetical capital structure for ratemaking purposes with 49.1 percent common equity ratio.

2. Cost of Equity

43 PacifiCorp has no publicly traded stock. It is wholly-owned by MEHC.[38] PacifiCorp's equity cost therefore must be estimated by analyses of investor's expectations for companies of comparable risk and other factors observable in financial markets.

44 Analysts make these estimates using a variety of methods. The most widely accepted approach is the discounted cash flow (DCF) method.[39] Its theory is that the market value of stock is the present value of the future cash flows, both dividends and growth, of holding the stock. The stream of future cash flows is discounted back to present value, typically using a simplified formula with stated assumptions.[40] There are several variants of the DCF methodology usually with a focus on how to assess the future growth (or the "g" factor on a forward-looking basis).

45 Other methods estimate the cost of equity based on what investors may require to compensate them for the investment risk of holding equity instead of investing in a safer financial instrument such as a bond. These methods include risk premium analysis that compares the equity risk premium to a bond instrument such as a

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[37] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 43 (Mar. 25, 2011).

[38] MEHC, in turn, is privately held as one of the Berkshire-Hathaway family of companies. Berkshire-Hathaway is publicly traded.

[39] *See* Hadaway, Exh. No. SCH-1T at 20:6-7.

[40] *See* James C. Bonbright, *et al.*, *Principles of Public Utility Rates* 317-22 (1988).

Treasury bond or investment-grade corporate bond. Another method is the capital asset pricing model (CAPM), which is based on a theory of economically efficient investments that employs the concept of a "risk-free rate" and a "beta" (i.e., a measure of volatility of stock price movements) to develop cost of equity.[41]

46 We have testimony in this case from three cost-of-capital experts: Dr. Hadaway for PacifiCorp, Mr. Elgin for Staff, and Mr. Gorman for Boise White Paper. These three experts rely on standard financial modeling approaches for estimating PacifiCorp's return on equity using varying interpretations of the DCF, risk premium, and CAPM. Table 6 shows the range in analytic results calculated by the cost-of-capital experts.

TABLE 6
Return on Equity Analytical Estimates

	Hadaway Direct	Elgin	Gorman	Hadaway Rebuttal
DCF				
Constant Growth (Analysts' 5-year growth)	**9.4 – 9.5%**	**9.0%**	**9.21%**	**9.0%**
Constant Growth Long-Term Growth or Sustainable Growth	**9.9 – 10.0%**		**8.38%**	**9.6%**
Two-Stage or Multi-Stage	**9.8 – 9.9%**		**8.91%**	**9.4%**
CAPM				
Current Interest Rates	**7.55 – 7.72%**		**8.5%**	
Projected Interest Rates	**8.08 – 8.25%**			
Risk Premium				
Current Interest Rates	**9.29%**		**9.05%**	**9.55-9.85%**
Projected Interest Rates	**9.60%**		**9.44%**	**9.97%**
Recommendation	**10.00%**	**9.00%**	**9.20%**	**10.00%**

[41] *Id.* at 322-28.

47 Dr. Hadaway gathers market price and dividend information for a proxy group of 14 companies he asserts are comparable to PacifiCorp.[42] Mr. Elgin eliminates six companies from Dr. Hadaway's group, contending that they differ materially due to nuclear construction risk, excessive revenues from unregulated operations, or customer segmentation.[43] Mr. Gorman eliminates one company from Dr. Hadaway's group because of its involvement in a recent acquisition.[44] Dr. Hadaway agrees it would be appropriate to eliminate this company from the group of comparables going forward, but says "it will not affect the outcome."[45]

48 Dr. Hadaway testifies initially that the Commission should rely on the results of his DCF analyses that indicate that his comparable group's return on equity is in the range of 9.4 percent to 10.0 percent.[46] In his direct testimony, he cautions that the results of DCF, equity risk premium, and capital asset pricing models are all being influenced by the current, artificially low interest rate environment and low bond yields caused by the Federal Reserve's monetary policy.[47] He argues that we should ignore or significantly discount these current policies, since they distort financial markets. Dr. Hadaway urges us to set PacifiCorp's return on equity at the higher end of his estimated DCF range, 10.0 percent, derived under his constant growth model using a "g factor" based on historical gross domestic product (GDP) data compiled by the St. Louis Federal Reserve Bank.[48] He argues that his recommendation is consistent with the average allowed return on equity for his proxy group of 14 vertically integrated utilities with financial and operating characteristics similar to the Company.[49]

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[42] Hadaway, Exh. No. SCH-1T at 3:21-22.

[43] Elgin, Exh. No. KLE-1T at 17:7-14.

[44] Gorman, Exh. No. MPG-1T at 17:8-10.

[45] Hadaway, TR. 243:23-244:2.

[46] Hadaway, Exh. No. SCH-1T at 2:23 and 3:1.

[47] *Id* at 3:1-5.

[48] *Id* at 3:12-14.

[49] *Id* at 3:21-22.

49 In his rebuttal testimony, Dr. Hadaway provides updated DCF results that differ significantly from the results in his direct testimony. They indicate a high end return on equity of 9.6 percent under his constant growth model using long-term GDP growth. Dr. Hadaway's constant growth model using equity analysts' five-year growth as his g factor yields only a 9.0 percent return on equity.[50] He testifies, however, that his DCF results understate PacifiCorp's return on equity "because the dividend yields in these models have been artificially depressed by the government's stimulative monetary policies."[51] He says the market's reaction to a potential change in these policies is evident in his updated risk premium analysis, but these changes are not yet reflected in his DCF results.[52]

50 On rebuttal, Dr. Hadaway dismisses the DCF model because "it cannot move quickly enough to capture what's going on."[53] He encourages us to rely on risk premium analysis and "to use additional judgment about where interest rates are and about where market publications are telling you that interest rates are headed to decide what rate of return you should use."[54] Dr. Hadaway performed updated risk premium analyses "designed to capture the recent FOMC [Federal Open Market Committee] policy shift and the increasing interest rate environment that the FOMC announcement has created."[55] He contends the results of his updated modeling support a return on equity range of 9.6 percent to 10.0 percent.[56] Dr. Hadaway used three updated risk premium studies in his rebuttal testimony:

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[50] Hadaway, Exh. No. SCH-10T at 23:2-3.

[51] *Id.* at 23:3-5. We note that these same stimulative monetary policies were in place at the time PacifiCorp filed its case, yet Dr. Hadaway at that time urged that we use the results of his DCF modeling.

[52] *Id.* at 23:5-7.

[53] Hadaway, TR. at 233:6-12.

[54] *Id.*

[55] Hadaway, Exh. No. SCH-10T at 23:10-14. The Federal Open Market Committee (FOMC), which consists of the members of the Board of Governors of the Federal Reserve System and five Reserve Bank presidents, makes U.S. monetary policy. The FOMC holds eight regularly scheduled meetings during the year, and other meetings as needed.

[56] *Id.* at 23:10-11.

> One is what I traditionally do, I use the most recent three months. And I think this same thing Mike Gorman has done in some of his analysis. I used a forecasted interest rate that's based on the so-called Bloomberg forward curve, what's going to happen sort of through 2014. And then I did demonstrate what a spot interest rate will give you if you just looked at that.[57]

Using current three-month average interest rates, Dr. Hadaway derived a 9.55 percent return on equity. Spot interest rates yielded a somewhat higher 9.85 percent. He says that the spot interest analysis, however, did not yield the top of the range that he recommends. Instead, "[i]t's the *forecasted interest rate* that gets the ten percent."[58]

51 Boise White Paper argues that Dr. Hadaway gives no convincing reason for the Commission to abandon its use of the DCF model and:

> Dr. Hadaway's risk premium alone would require the Commission to set an ROE based on spot interest rates captured at the moment Dr. Hadaway developed his risk premium analysis, rather than relying on the multiple data points used to develop the analyses in all five models presented by Mr. Gorman.[59]

52 As discussed above, this is not exactly correct. Had Dr. Hadaway relied on the spot rate, the top of his range of risk premium estimates would have been 9.85 percent. In point of fact, Dr. Hadaway suggests that the Commission rely on a novel approach, looking at forecasted interest rates taking into account assumed changes in monetary policy by the Federal Reserve that are difficult to predict. Boise White Paper points out in this connection that:

> Contrary to Dr. Hadaway's predictions, the Federal Reserve did *not* change its monetary policy in September, and spot interest rates and bond yields have dropped significantly since his testimony.[60]

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[57] Hadaway, TR. at 232:21-233:3.

[58] *Id.* at 233:3-5 (emphasis added).

[59] Boise White Paper Initial Brief at 13.

[60] *Id.* (citing Michael P. Regan & Nick Taborek, *Stocks Rally With Treasuries, Gold, As Fed Resists Taper*, Bloomberg, Sept. 18, 2013, http://www.bloomberg.com/news/2013-09-17/asian-index-futures-rise-before-fed-as-crude-oil-rebounds.html).

Boise White Paper concludes that this highlights "the arbitrary and capricious nature of Dr. Hadaway's recommendation."[61]

53 Boise White Paper and Staff both support the Commission's traditional practice of assessing several methodologies, considering a broad range of data, and placing primary emphasis on the DCF methodology. Mr. Elgin explained in response to questions from the Bench that he is "an advocate of DCF because it relies on stock prices."[62] He argues that stock prices are centrally important because equity funds support the investment in the utility. "Those equity costs change slowly over time, and how they change over time is again reflected in the price investors are willing to pay for common equities."[63] Mr. Elgin testifies that in his expert opinion:

> There's way too much quibbling about, well, interest rates went this way and interest rates went down and up and what do you actually use for – in a risk premium study. Look at equity prices, look at how the market is reacting in relationship to what's happening in long-term interest rates, and then make a judgment.[64]

54 Boise White Paper argues similarly that "[t]he DCF model produces reliable results that correctly gauge the appetite of the market for utility stocks."[65] That said, Boise White Paper criticizes Dr. Hadaway's DCF modeling because his Gross Domestic Product (GDP) growth rate relies on historical inflation rates that are higher than current and forward looking inflation, thus assuming a GDP growth rate that is "far higher than the consensus economists' projected GDP growth rate for the next five to ten years."[66]

55 Staff also voices this criticism of Dr. Hadaway's analysis. Staff argues that:

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[61] *Id.*

[62] Elgin, TR. 234:13-14.

[63] *Id.* at 234:14-20.

[64] *Id.* at 234:21-235:2.

[65] Boise White Paper Initial Brief at 13.

[66] *Id.* at 14.

> Dr. Hadaway's reliance on historical GDP growth data is perplexing since the Commission has rejected his approach in the Company's last two cases:
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> - In the 2005 case, the Commission stated, "However, in this case we find persuasive Mr. Gorman's argument, that if growth in GDP is used for this critical input to the DCF formula, it should be forward-looking, not an historical average."[67]
> - In the 2010 case, the Commission again rejected Dr. Hadaway's use of historical GDP data and specified that if GDP data is to be used at all it should be short-term estimates of GDP.[68]

56 Mr. Elgin performs his DCF analysis looking at financial information for his proxy group, which is a subset of the 14 companies Dr. Hadaway identifies as being comparable to PacifiCorp. Relying on *Value Line, Morningstar* and Dr. Hadaway's data, Mr. Elgin concludes that a reasonable estimate for investors' expected dividend yield for his proxy group is between 4.00 and 4.25 percent.[69] He uses the upper end of this range in his final analysis. To estimate long-term, or sustainable, growth rate for dividends, Mr. Elgin gives primary weight to growth in book value and internal growth. These two metrics show growth of 4.0 percent and 3.9 percent, respectively.[70] He also considers *Value Line's* expected growth rate for dividends that show slightly higher growth of 4.1 to 4.6 percent, or an average of 4.35 percent.[71] Finally, although he cautions against giving much weight to analysts' estimates of earnings, he finds "a high case estimate is 4.75 percent."[72] Mr. Elgin concludes that a reasonable estimate of long-term growth in dividends is in the range of 4.00 to 4.50 percent.[73] Finally, he says that "if primary weight is given to earnings estimates, a

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[67] Staff Initial Brief ¶ 50 (citing *WUTC v. PacifiCorp*, Docket UE-050684, Order 04 ¶261 (April 17, 2006)).

[68] *Id.* (citing *WUTC v. PacifiCorp,* Docket UE-100749, Order 06 ¶82 (March 25, 2011)).

[69] Elgin, Exh. No. KLE-1t at 25:5-21.

[70] *Id.* at 27:18-28:1 and 29:6-8.

[71] *Id.* at 29:10-12.

[72] *Id.* at 29:14-32:14.

[73] *Id.* at 32:16-20.

growth rate of 4.75 percent is the most any reasonable investor could expect."[74] Mr. Elgin summarizes his DCF analysis as follows:

> My estimated average dividend yield for my proxy group is 4.00 to 4.25 percent. The indicated growth rate in dividends is 4.00 to 4.50 percent. This indicates a ROE estimate of 8.00 to 8.75 percent. If I combine the high end of my range for dividend yield of 4.25 percent with an earnings estimate of 4.75 percent, it produces an ROE of at most 9.00 percent. Therefore, I conclude that a fair ROE for PacifiCorp is between 8.50 and 9.00 percent.[75]

57 Mr. Gorman relies on the results of five financial models, including: 1) a Constant Growth DCF model; 2) a Sustainable Growth DCF model; 3) a Multi-Stage Growth DCF model; 4) a Risk Premium model; and 5) a CAPM. Mr. Gorman's Constant Growth DCF model uses a 13-week average of stock prices for his proxy group. He testifies that this captures a period recent enough to reflect current market trends, but not so short as to be susceptible to short-term changes that do not reflect the stock's fundamental market value.[76] For the DCF model's dividend component, Mr. Gorman uses PacifiCorp's most recent quarterly dividend, as reported by Value Line, annualized and adjusted for next year's growth.[77] For the Constant Growth model, to estimate the g factor, he used an average of professional analysts' growth rate estimates representing a consensus, derived from *Zack's Investment Research*, *SNL Financial*, and *Reuters*. Mr. Gorman's Constant Growth model suggested an average and a median return of 9.21 percent and 9.33 percent, respectively.[78] He opines these results are likely overstated, because three- to-five-year growth rates are above the sustainable long-term growth rate.

58 Mr. Gorman's Sustainable Growth DCF recognizes that, as rate base grows through reinvested earnings, the dividend payout ratio of the company must decline. Thus, he uses a long-term earnings retention growth rate to help gauge whether the consensus

[74] *Id.*

[75] *Id.* at 33:1-7.

[76] Gorman, Exh. No. MPG-1T at 19:18-21.

[77] *Id.* at 20:3-5.

[78] *Id.* at 21:16-17

three- to-five-year growth rate can be sustained over a long term. This model produced average and median DCF results of 8.38 percent and 8.35 percent, respectively.[79]

59 Mr. Gorman developed a Multi-Stage Growth DCF model that that adjusts for the recent cycle of capital investment in the utility sector, and posits that the g factor should be similar to the projected growth in U.S. GDP.[80] He testifies that this is because utility construction cycles tend to produce periods of increased investment, which eventually must level out and cannot exceed the long-term growth of the economy generally.[81] Mr. Gorman's Multi-Stage Growth DCF model produces an average and median return on equity of 8.91 percent and 8.88 percent, respectively.[82]

60 For his overall DCF recommendation, Mr. Gorman averaged the results of his three models, weighing the Constant Growth and Multi-Stage models more heavily than the Sustainable Growth model that suggests the lowest rate of return. This resulted in a 9.10 percent return on equity for PacifiCorp.[83]

61 Mr. Gorman also performed a risk premium analysis based on the 13-week average yield spreads between Treasury bonds and "A" rated and "Baa" rated utility bonds.[84] This analysis, weighted to recognize the large yield spreads between Treasury bonds and utility bonds, produced a low end return on equity of 9.05 percent and a high end estimate of 9.44 percent.[85] Mr. Gorman testifies that the midpoint of these estimates suggests an equity risk premium return on equity of 9.25 percent.[86]

62 Finally, Mr. Gorman developed a CAPM model. This was based on *Morningstar's* market risk premium of 6.7 percent, a risk free (30-year Treasury bill) rate of 3.70%,

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[79] *Id.* at 23:4-5.

[80] *Id.* at 24:28-25:11.

[81] *Id.*

[82] *Id.* at 28:11-12.

[83] *Id.* at 28:14-17.

[84] *Id.* at 29:1-33:12.

[85] *Id.*

[86] *Id.* at 33:13-14.

and a beta of 0.71. His assumptions and modeling produced an overall return on equity of 8.47 percent, which Mr. Gorman rounded up to 8.50 percent.[87] Given his concerns with the risk free rate and market risk premium, Mr. Gorman placed minimal weight on the CAPM result.[88]

63 *Commission Determination:* PacifiCorp's currently authorized return on equity is 9.8 percent. The Company failed to carry its burden in this case to support its proposed 10.0 percent return on equity. Indeed, Dr. Hadaway's own analyses provide evidence supporting a substantially lower rate of return. The full record supports our approval of a 9.5 percent return on equity for PacifiCorp, within a range of reasonable returns from 9.0 percent to 9.7 percent. This determination reflects our view that the principle of gradualism should apply when setting key factors such as rates of return regardless of the direction of a change. Thus, we authorize a return on equity for PacifiCorp closer to the high end of the range of reasonableness supported by the record.

64 Dr. Hadaway suggests that we not rely on his DCF modeling and rely instead on his risk premium analysis using highly variable spot and forecasted interest rates as presented on rebuttal. We are not prepared, however, to reject DCF analysis as a viable means to estimate reasonable rates of return on equity. We find it worthwhile to consider, along with his other evidence and the evidence presented by Mr. Elgin and Mr. Gorman, what Dr. Hadaway's DCF modeling results actually support.[89]

65 In his direct evidence, Dr. Hadaway relied principally on his sustainable growth DCF model using long-term GDP growth for the g factor. We agree with Boise White Paper and Staff that this approach is flawed by virtue of Dr. Hadaway's reliance on historical GDP data. The Commission has twice previously rejected this approach in

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[87] *Id.* at 39:2-4.

[88] *Id.* at 29:11-15.

[89] The Commission emphasized in PacifiCorp's most recent fully litigated case that it places value on each of the methodologies used to calculate the cost of equity and does not find it appropriate to select a single method as being the most accurate or instructive. "Financial circumstances are constantly shifting and changing, and we welcome a robust and diverse record of evidence based on a variety of analytics and cost of capital methodologies." *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 91 (March 25, 2011). *See also WUTC v. Puget Sound Energy,* Dockets UE-090704 and UG-090705 (consolidated), Order 11 (April 2, 2010).

favor of short-term, forward looking estimates of GDP.[90] While we would not, for this reason, establish an equity return rate relying on this key assumption, we nevertheless can view the results as informing our determination of a range of reasonableness.

66 Dr. Hadaway's initial long-term, or sustainable, growth modeling produced return on equity estimates in the range of 9.9 to 10.0 percent, while his later modeling using his favored approach produced an estimate of 9.6 percent. This leads us to consider whether the approximate mid-point of these estimates, 9.8 percent, might represent the higher end of a range of reasonable returns. This is suggested, too, by the results of Dr. Hadaway's two-stage analyses that yielded results in the 9.4 percent (rebuttal) to 9.9 percent (initial) range. The approximate midpoint of these results, 9.7 percent, provides additional support for such a conclusion.

67 Dr. Hadaway's constant growth model, with long-term expected growth based on analysts' estimates of five-year utility earnings growth, yields results in a 9.0 percent (rebuttal testimony) to 9.5 percent range (direct testimony). While this is not Dr. Hadaway's preferred method, and Mr. Elgin cautions against placing too much reliance on short-term projections by analysts, we can consider these results as being at least suggestive of a low-end marker. Mr. Gorman's analyses suggest an even lower end when we focus on the 8.38 percent return yielded by his sustainable growth DCF model. This view is tempered somewhat, however, by Mr. Gorman's risk premium result of 9.25 percent, using current interest rates, by his constant growth DCF at 9.21 percent, and by his recommendation based on all of his modeling for a 9.20 percent return on equity. Considering all of this, and Mr. Elgin's recommendation of a 9.0 percent return on equity based on his long-term growth DCF model, we can confidently establish 9.0 percent as the low end of the range indicated by the full body of evidence before us. Indeed, this is a conservative determination considering that it is at the high end of Mr. Gorman's and Mr. Elgin's estimates.

68 Dr. Hadaway's risk premium analyses produce results in the range from 9.29 percent (direct testimony) to 9.97 percent (rebuttal testimony). However, we give little weight to the higher end of these results considering that they rely on forecasted interest rates and assumptions concerning actions by the Federal Reserve that did not,

[90] *See supra* ¶ 58.

in fact, occur.[91] Dr. Hadaway's risk premium analyses that produce the most credible results are those that rely on current (three-month) interest rates rather than a spot rate or a forecasted rate. The range of these is from 9.29 percent (direct testimony) to 9.55 percent (rebuttal testimony).

69 Even if we were to accept Dr. Hadaway's argument on rebuttal that we abandon the DCF method and adopt his risk premium analyses, we find his risk premium model supports a return on equity of no more than 9.6 percent.[92] Moreover, we choose not to ignore entirely that his long-term growth DCF model on rebuttal also supports a 9.6 percent return on equity.

70 Mr. Elgin's DCF modeling supports his recommended 9.0 percent return on equity. Giving this result equal weight with the 9.6 percent level Dr. Hadaway's evidence supports, we could justify setting PacifiCorp's return at 9.3 percent. Similarly, giving equal weight to Mr. Gorman's DCF results of 9.2 percent and the credible results from Dr. Hadaway's DCF modeling, we could justify authorizing a 9.4 percent return. PacifiCorp's currently authorized return on equity, however, is 9.8 percent and the principle of gradualism should be part of our consideration. Indeed, this persuades us to temper the final recommendations of Mr. Elgin and Mr. Gorman, and place more weight on the higher end of the range of reasonableness. Therefore, we finally determine that PacifiCorp's return on equity should be authorized at 9.5 percent based on the record developed in this proceeding.

3. Cost of Debt

71 PacifiCorp's actual cost of long-term debt is not in dispute. We elect to not impute directly short-term debt in the Company's capital structure. Our continued use of the hypothetical capital structure discussed in the preceding section of this Order, however, adequately accounts for short-term debt and obviates the need to make any

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[91] *See, e.g.,* Hadaway, Tr. 149:2-9; 240:6-12.

[92] As discussed above, Dr. Hadaway's risk premium model based on actual three-month interest rates yields a 9.55 percent return on equity, only .05 percent higher than what we approve in this case.

additional adjustment to PacifiCorp's debt costs. We find reasonable a 5.29 percent overall cost of debt, as proposed by the Company for long-term debt.[93]

4. Cost of Preferred Stock

72 PacifiCorp's cost of preferred stock is not disputed. We approve the use of 5.43 percent as the Company's cost of preferred stock.

5. Capital Structure and Cost of Capital Summary

73 *Commission Determination:* We summarize in Table 7 our determinations of the capital structure and costs for PacifiCorp that we find are best supported by the evidence. These determinations meet both the Company's needs and the ratepayers' needs.

TABLE 7
Commission Determination of Capital Structure and Cost of Capital

	Share percent	**Cost percent**	**Weighted Cost percent**
Equity	49.1	9.50	4.66
Long-Term Debt	50.62	5.29	2.68
Preferred Stock	0.28	5.43	0.02
OVERALL ROR			**7.36**

C. Inter-Jurisdictional Cost Allocation

74 The parties' respective positions on the issue of inter-jurisdictional cost allocation are best understood in their historical context. The Commission established rates for the

[93] This should not be read as establishing Commission policy that utilities should not include short-term debt in their capital structure when filing rate cases. Indeed, generally, and depending on actual rates, use of short-term debt as a means of financing company operations is cost-effective, and a company should consider all available sources of capital. Elgin, Exh. KLE-1T at 15:6-7, *citing WUTC v. PacifiCorp*, Docket UE-050684, Order 04 ¶ 224 (April 17, 2006).

Company, then doing business in Washington as Pacific Power & Light Co. (PP&L), in 1986.[94] Although PP&L provided service in multiple states at the time, the problem of allocating costs among them was resolved on the basis of consensus among representatives from the six states and the Company.[95] The Commission accepted a cost allocation based on average system costs.

75 This was just prior to the merger between PP&L and Utah Power in August 1987. In its order approving the merger, the Commission referred to Staff testimony showing a material difference between the average system costs of the two companies. The Commission stated its concern "about the effects on Pacific's ratepayers of merging with a higher cost system."[96] The Commission said, however, that for the time being it was satisfied with the use of PP&L's pre-merger average system cost as the basis for rates in Washington, as just approved in September 1986.[97] The Commission ordered that:

> The merged company is authorized and directed to adopt tariff schedules and special service contracts of [PP&L], for service within Washington on file with the Commission and in effect as of the effective date of the merger.[98]

76 The Company did not file another general rate case in Washington for 14 years. In Docket UE-991832, the Commission approved and adopted a comprehensive, "black box" settlement agreement among all parties. The settlement did not address, and the Commission's order does not discuss, the subject of inter-jurisdictional cost allocation.

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[94] *WUTC v. Pacific Power & Light Co.*, Cause U-86-02, Second Supplemental Order (Sept. 19, 1986).

[95] *Id.* at 33.

[96] *In the Matter of the Application of PacifiCorp (Maine) to Merge with PC/UP&L Merging Corp. (PacifiCorp Oregon), and to Issue such Securities and Assume such Obligations as May be Necessary to Effect a Merger with Utah Power & Light Company*, Docket U-87-1338-AT, Second Supplemental Order Approving Merger with Requirements at 14 (July 15, 1988).

[97] *Id.*

[98] *Id.* at 16, Ordering ¶ 2.

77 The settlement approved in Docket UE-991832 established a five-year rate plan with predetermined increases in rates authorized for each of the first three years, followed by two years of no increases in general rates. However, the Western energy crisis intervened. In an order rejecting PacifiCorp's request for deferred accounting for "excess" power costs incurred to serve Washington customers, the Commission determined that:

> The Rate Plan has been so overtaken by events that it no longer is in the public interest for the Company's rates to remain unexamined through the Rate Plan Period. We emphasize that the record in this proceeding is not an adequate one upon which to conclude that PacifiCorp's current rates are not fair, just, reasonable, and sufficient. The record here, however, is adequate to bring into question whether that standard will be satisfied when considered in light of a current test year with properly restated, normalized, and pro formed results. PacifiCorp's Washington operations have not been thoroughly reviewed on a full general rate case record in 17 years. Such an examination is long overdue and seems absolutely imperative in the wake of the recent power market crisis. It would be contrary to the public interest for us to bar this important matter from full consideration at an early date. Accordingly, we conclude that we should amend our Third Supplemental Order in Docket No. UE-991832 to the extent necessary to authorize PacifiCorp to file a general rate case prior to the end of this year as the Company has committed to do, if permitted. [99]

PacifiCorp filed the authorized general rate case, breaking the Rate Plan, on December 16, 2003, in Docket UE-032065. The case was ultimately resolved, after a full hearing, on the basis of Commission approval of a contested settlement. The settlement order resolved a few discrete issues, left others for further consideration in a future case, and approved what was in main part a "black box" revenue requirement.

78 The Commission discussed in its final order approving the settlement the fact that inter-jurisdictional allocation of costs among the states PacifiCorp serves had been a continuing source of controversy since the time of the merger. Referring back to the prior case in Docket UE-991832, the Commission observed that:

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[99] *Re PacifiCorp*, Dockets UE-991832 and UE-020417, Sixth/Eighth Supp. Order ¶¶ 22-23 (July 15, 2003).

> The Company proposed that costs be allocated to Washington rates according to a methodology to which Commission Staff, and other parties, strenuously objected. The proceeding . . . was resolved on the basis of the Commission's approval and adoption of a full settlement among all parties that implicitly reserved for another day any definitive resolution of the complex issues involved in inter-jurisdictional cost allocation.[100]

79 In PacifiCorp's 2005/2006 general rate case, the Company's failure to satisfy its burden to prove an acceptable allocation methodology was the defining point in the Commission's decision.[101] The Commission rejected PacifiCorp's suspended tariff sheets in favor of the status quo, relying in part on the fact that the resources the Company attempted to assign as costs to Washington were not in fact proven to be used and useful for service in Washington, as required by RCW 80.04.250. The Commission interpreted the phrase "used and useful for service in this state" to mean the resource in question must provide to ratepayers in Washington either direct benefits "(*e.g.,* flow of power from a resource to customers)" or indirect benefits "(*e.g.,* reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits)."[102] Moreover, "[u]nder either circumstance, the Company must demonstrate a quantifiable benefit to Washington ratepayers."[103] Noting Staff's concession that some indirect benefits were attributable to integration of PacifiCorp's east and west control areas, the Commission said that:

> [T]he Company has simply failed to establish the value of any tangible benefits flowing to Washington ratepayers. The Company's position is most plainly stated in the testimony of Mr. Duvall: "The Revised Protocol does not require that we demonstrate a "State-specific" benefit for particular resources before they can be recovered in a particular

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[100] *WUTC v. PacifiCorp,* Docket UE-032065, Order 06 ¶ 15 (October 27, 2004) (citing *WUTC v. PacifiCorp,* Third Supp. Order, Docket UE-991832 (August 9, 2000)).

[101] *WUTC v. PacifiCorp,* Docket UE-050684, Order 04 ¶ 64 (April 17, 2006) "The Company bases its entire general rate case in this proceeding on the Revised Protocol. Without a method to allocate costs (rate base and expenses) to Washington, we are not able to establish whether the proposed rates would be fair, just or reasonable, and reject the Company's tariffs, as filed.".

[102] *Id.* ¶ 50.

[103] *Id.* ¶ 51.

> State's retail rates." The Revised Protocol may not require such a showing, but Washington law does.[104]

Finding that PacifiCorp did not meet its burden to show that the resources included in the Revised Protocol were used and useful for service in Washington, the Commission found that the Company failed to meet its burden to show that the rates proposed in Docket UE-050684 would be fair, just and reasonable. The Commission rejected the Company's as-filed tariffs on this basis and found further that it could not establish rates different from those then in effect because the Company based its entire case on a cost allocation methodology unacceptable to the State of Washington.

80 In the Company's next general rate case the Commission approved PacifiCorp's proposed West Control Area (WCA) cost-allocation methodology for Washington, with two agreed-upon Staff adjustments.[105] With the modifications it proposed, Staff testified that the WCA "meets the standards enunciated by the Commission" and "is appropriate for purposes of setting retail electric rates for PacifiCorp's Washington customers."[106] The Commission also approved the Company's recommended five-year trial period for this cost-allocation methodology and Staff's recommended "oversight committee."[107] The Commission expressly rejected "all other proposed modifications to the WCA."[108]

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[104] *Id.* ¶ 54 (internal citation to record omitted).

[105] *WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817 (consolidated), Order 08, ¶¶ 49-52 (June 21, 2007). The WCA includes PacifiCorp's California, Oregon and Washington loads and resources and some generation resources, such as Colstrip and Jim Bridger, which are located outside Washington, Oregon and California, but have adequate transmission to provide delivery to Washington customers. The WCA method isolates the costs associated with these assets, purchases and sales, and allocates to Washington a proportionate share of the costs based on Washington's relative contribution to the WCA's demand and energy requirements. Staff's proposed modifications, to which the Company agreed, were to impute benefits to the WCA from market sales to the ECA considering transmission availability and market prices, and to use 75 percent demand-related and 25 percent energy-related factors to allocate fixed production costs in the Control Area Generation-West (CAGW), and to allocate general and intangible plant and administrative and general (A&G) expenses that cannot be directly assigned.

[106] *Id.* ¶ 46 (citing Staff Initial Brief ¶ 13).

[107] *Id.* ¶ 43.

[108] *Id.*

81 It remains significant today that in approving the WCA, a method different than the Revised Protocol on which PacifiCorp relies in its five other states for inter-jurisdictional cost allocation, the Commission recognized that the Company assumed any risk of under-recovery of costs due to states approving different methodologies:

> The Company claims that it is entitled to full recovery of its prudently incurred costs systemwide and should not bear the risk that state decisions about cost recovery will not, in combination, ensure this entitlement. The Company points to no provision of law in support of this proposition. In fact, the Company created and accepted the risk that divergent allocation decisions among the states might result in under-recovery when it chose to merge 20 years ago. Our order approving that merger read together with the merger order of the Oregon Commission[109] make clear that this risk existed, that the Company was aware of it, and that the Company accepted that it alone would bear the risk. The Oregon Commission's order, indeed, is perfectly clear on this point:
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>> Pacific agrees, however, that its shareholders will assume all risks that may result from less than full system cost recovery if interdivisional allocation methods differ among the merged company's jurisdictions.[110]

82 PacifiCorp used the approved WCA method in its 2008, 2009, 2010 and 2011 general rate cases in Dockets UE-080220, UE-090205, UE-100749, and UE-111190, respectively. The Commission extended the WCA trial period in the 2011

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[109] *In the Matter of the Application of PacifiCorp and PC/UP&L Merging Corp. for an Order Authorizing the Merger of PacifiCorp and Utah Power & Light Company into PC/UP&L Merging Corp. (to be Renamed PacifiCorp upon Completion of the Merger), and Authorizing the Issuance of Securities, Assumption of Obligations, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity, Allocated Territory, and Authorizations in Connection Therewith*, Public Utility Commission of Oregon Docket UF 4000, Order 88-767 (July 15, 1988) (Oregon Merger Order); s*ee also In the Matter of the Application of PacifiCorp (Maine) to Merge with PC/UP&L Merging Corp. (PacifiCorp Oregon), and to Issue such Securities and Assume such Obligations as May be Necessary to Effect a Merger with Utah Power & Light Company*, WUTC Docket U-87-1338-AT, Second Supplemental Order Approving Merger with Requirements at 14 (July 15, 1988) (Washington Merger Order).

[110] Oregon Merger Order at 6.

proceeding, as the parties requested, to allow time for a more thorough discussion in a collaborative process among interested stakeholders.[111]

83 The collaborative process took place but it did not result in any agreements among the participants for changes to the previously approved WCA cost-allocation methodology. The Company nevertheless filed its next general rate case, this case, using a revised WCA cost-allocation methodology. Staff and other parties oppose the revisions that PacifiCorp unilaterally made in its filing.

1. Should the Commission accept proposed revisions to the WCA?

84 The starting point for determining the revenue requirement in any general rate case is referred to as the "per books" portrayal of the Company's results of operations during the test period. Application of the WCA methodology has determined the Washington per books amounts for PacifiCorp's revenues, expenses, and rate base in its last several rate cases, since the methodology was approved in 2007.[112] PacifiCorp filed its case in this docket using different allocation factors to establish this per books baseline than what the Commission approved in Docket UE-061546 in 2007.

85 The Company proposes several modifications to the WCA method. Three of these impact the calculation of net power costs, discussed separately below.[113] Additional modifications proposed by PacifiCorp affect non-power costs primarily through the development of the Control Are Generation West (CAGW) allocation factor, as follows:

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[111] *WUTC v. PacifiCorp*, Docket UE-111190, Order 07, Settlement Stipulation at ¶¶ 28-29 (February 21, 2012).

[112] *WUTC v. PacifiCorp,* Docket UE-061546, Order 08 (June 21, 2007).

[113] Briefly, these are:

- Inclusion of all power purchase agreements with qualified facilities located in PacifiCorp's west control area.
- Removal from the calculation of net power costs all revenues from the imputed sale from PacifiCorp's west control area to PacifiCorp's east control area.
- Recognition of the full capacity of the Company's point-to-point transmission contract with Idaho Power Company.

- Changing the weighting used to calculate the CAGW allocation factor from 75 percent demand over 25 percent energy to 38 percent demand over 62 percent energy.[114]

- Using the highest 100 winter hours and highest 100 summer hours (200 coincident peaks) to calculate the demand-related base components within the CAGW allocation factor, instead of using the 12 coincident peaks in the approved methodology.[115]

The Commission ordered the use of the 75/25 demand/energy ratio for the CAGW in the Company's 2006/2007 case following Staff's recommendation, to which the other parties agreed. In approving the WCA cost-allocation and Staff's modification, the Commission said:

> We find the WCA cost-allocation for Washington, modified by our adoption of Staff's adjustments 5.4 and 5.5, produces results that are consistent with the requirements for an allocation methodology that we have discussed in prior orders, particularly our Final Order in PacifiCorp's 2005 Rate Case. It is in the public interest for us to approve the WCA method. We reject all other modifications proposed by ICNU and Public Counsel.[116]

Use of the 12 coincident peaks was part of PacifiCorp's original proposal for the WCA model, as approved by the Commission.

86 PacifiCorp's changes to CAGW impact the calculation of several other allocation factors that are partially based on CAGW, such as the System Overhead (SO), the Jim Bridger Generation (JBG), System Net Plant Transmission (SNPT), Wheeling Revenue – Generation (WRG), and Wheeling Revenue – Energy (WRE) factors. The

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[114] Dalley, Exh. No. RBD-1 at 6:10-15; *See also* McDougal, Exh. No. SRM-5 at 11.

[115] Dalley, Exh. No. RBD-1 at 6:16-19.

[116] *WUTC v. PacifiCorp,* Docket UE-061546, Order 08 ¶ 57 (June 21, 2007). Staff Adjustment 5.4 imputes benefits to the WCA from market sales to the east control area considering transmission availability and market prices. Staff Adjustment 5.5 modifies the allocation of fixed production costs in the CAGW and SO allocation factors to be 75 percent demand-related and 25 percent energy-related. *Id.* ¶ 45.

result of PacifiCorp's revisions to the cost allocation model, in aggregate, increased the Company's revenue requirement by approximately $800,000.[117]

87 Because PacifiCorp did not provide a comprehensive review of the WCA method prior to presenting its case, Staff recommends that the Commission reject its selective modifications and again establish the Company's revenue requirement using the original WCA allocation methodology approved in Docket UE-061546.[118] Staff discusses how PacifiCorp's selective changes to the WCA create inconsistencies between the CAGW and System Generation (SG) allocation factors. The SG allocation factor is used to allocate generation- and transmission-related costs that cannot be assigned to a specific control area.[119] The CAGW allocation factor is used to allocate generation- and transmission-related costs that are assigned to the WCA.[120] In the approved WCA method, the weighting for both factors is 75 percent demand and 25 percent energy. Even though the factors are conceptually similar because they apportion generation- and transmission-related resources between demand costs and energy costs, PacifiCorp now proposes to use different allocation ratios for these two factors.[121]

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[117] White, Exh. No. KAW-1CT at 12:1-9, footnote 21 ("The total dollar impact of this change is approximately $800,000 according to PacifiCorp's response to Boise White Paper's Data Request No. 3.3, first revision.").

[118] Staff allows for one minor exception that relates to power costs, which are discussed separately below. Ms. White notes in her testimony that:

> Staff accepts one of two changes the Company is proposing to the Jim Bridger Generation ("JBG") allocation factor. Staff witness David Gomez accepts expenses related to the new Idaho Power point-to-point wheeling contract. This change impacts the JBG allocation factor [because] one of the base components [of the allocation factor] is Jim Bridger's WCA transmission capacity. As discussed in my testimony, however, Staff does not accept the other change to JBG that results from the Company's proposed revision to the calculation of the Control Area Generation West ("CAGW") allocation factor.

Exhibit No. KAW-1CT at 3:10, footnote 1.

[119] McDougal, Exh. No. SRM-5 at 7.

[120] McDougal, Exh. No. SRM-5 at 11.

[121] By changing the CAGW allocation factor to a 38/62 ratio, PacifiCorp increases the costs allocated to Washington. If PacifiCorp treated the SG factor consistently (*i.e.*, also changed it to a 38/62 ratio) this would reduce the costs allocated to Washington. *See* Staff Initial Brief ¶¶ 116-17.

88 Staff also criticizes PacifiCorp's failure to address the controversial System Overhead (SO) allocation factor in its proposal to modify the WCA methodology. The SO allocation factor is used to allocate general and intangible plant and general A&G expenses that cannot be directly assigned. General and intangible plant and general A&G expenses are common costs not directly involved in production, transmission, and distribution, or the provision of customer services. The current SO factor is based on each state's percentage of total Company gross plant.[122] Staff argues that an allocation factor based on net plant will produce more accurate and equitable results than the current SO factor based on gross plant because a gross-plant based allocation over-allocates costs to slower growing jurisdictions.[123] Staff believes a comprehensive review of the WCA method is required to address this issue.[124]

89 Given these deficiencies, Staff argues, there is no basis to conclude that the Company's selective revisions fairly allocate total system costs to Washington.[125]

90 Public Counsel's arguments are consistent with Staff's. Public Counsel witness Mr. Coppola testifies that he sees no logical basis for changing the CAGW allocation factor to a 38/62 demand/energy ratio, particularly since the Company uses a 75/25 weighting for other allocation factors.[126] Mr. Coppola also addresses the Company's use of the SO factor, arguing it over allocates costs to Washington. He, too, recommends that the Commission use instead the System Net Plant (SNP) allocation factor. Mr. Coppola testifies that "[t]his is a more appropriate factor which reflects the fact that older more established plant facilities require less management and administrative attention than newly built facilities."[127]

91 Staff also recommends that the Commission order PacifiCorp to file a report at least 90 days before its next full general rate case including specific additional information

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[122] McDougal, Exh. No. SRM-5 at 7.

[123] Staff Initial Brief ¶ 109. *See also id.* ¶¶ 126, 131.

[124] *Id.* ¶ 132.

[125] *Id.* ¶ 104.

[126] Exhibit No. SC-1CT at 5:6-13.

[127] *Id.* at 5:14-19.

regarding the allocation factors that are disputed in this case.[128] Staff argues that while it is desirable to have a comprehensive review of this subject, there was not sufficient time in this case for such a review by Staff.[129] Staff argues that "a comprehensive review of the WCA method does not end with the identification of concerns regarding current allocation factors, as occurred in the collaborative."[130] Staff continues:

> It must also provide for the development of new allocation factors and consideration of their impact on the WCA method as a whole. The Company explained that creating a new allocation factor within the revenue requirement models presents significant difficulties. [131] Staff's recommendation to maintain the status quo in this case, but require a Report that will assist in examining possible revisions, isolates allocation issues and impacts so that a comprehensive review can occur in the next case.[132]

92 *Commission Determination:* The WCA methodology is the only inter-jurisdictional cost allocation methodology proposed since the merger of PP&L and Utah Power in 1987 that the Commission has approved. It is a comprehensive methodology with multiple factors. We believe that any changes should be considered in the context of an overall review of that methodology.

93 The change to the CAGW allocation factor that PacifiCorp proposes here would reverse one of the two modifications the Commission ordered to PacifiCorp's proposed allocation methodology when approving the WCA in Docket UE-061546. In addition, the change would more closely align the WCA methodology with the Revised Protocol, which uses the 38/62 ratio. Yet, the Commission expressly rejected the use of a 38/62 weighting of the CAGW allocation factor in Docket UE-061546,

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[128] Staff Initial Brief ¶ ¶ 105-06.

[129] *Id.* ¶ 112.

[130] Dalley, Exh. No. RBD-2.

[131] Dalley, Exh. No. RBD-5CX. For example, Staff considered developing a new blended allocation factor for the apportionment of general A&G expense. The Company stated that creating a new allocation factor would "require updates to almost every tab in both the Regulatory Allocation Model ("RAM") and Jurisdictional Allocation Model ("JAM"), in addition to updating the defined ranges in the macros."

[132] Staff Initial Brief ¶ 113.

and expressly rejected the Revised Protocol in Docket UE-050684.[133] PacifiCorp has not demonstrated to our satisfaction that there is any reason to reverse the direction taken in the Commission's earlier orders.

94 Unless the Company, with or without the agreement of the parties affected by the use of the WCA methodology, demonstrates that any change proposed more closely aligns the allocation of costs based on causation, we see no reason to disturb it. For the Commission to endorse any unilateral change, or any change that is disputed, the party advocating the change must make a detailed and persuasive showing demonstrating that the proposed change is appropriate. No change proposed by any party in this proceeding is supported by such a showing. We accordingly require PacifiCorp to use an unmodified WCA inter-jurisdictional cost allocation when preparing its compliance filing in this docket. Putting net power costs to one side for the moment, this will reduce the Company's revenue requirement by approximately $800,000.

2. Net Power Costs

95 PacifiCorp's proposed net power costs (NPC) at the time of its Initial Brief are $570.3 million on a west control area basis.[134] The Company allocates $129.1 million in NPC to Washington.[135] This is an increase of about $5 million relative to the NPC embedded in current rates.

96 Staff, Public Counsel, and Boise White Paper each raise issues with respect to the determination of power costs. They challenge PacifiCorp's proposed treatment of certain costs under the WCA (*i.e.,* Public Utilities Regulatory Policies Act (PURPA)[136] Qualifying Facilities (QF) costs, imputed sales from West Control Area

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[133] *WUTC v. PacifiCorp*, Docket UE-050684, Order 04 ¶ 49 ("We reject the Revised Protocol as an inter-jurisdictional cost allocation method for use in this state.")

[134] PacifiCorp Initial Brief ¶ 53.

[135] *Id.*

[136] Pub.L. 95–617, 92 Stat. 3117 (enacted November 9, 1978). PURPA was part of the National Energy Act of 1978. Its purpose is to promote greater use of domestic renewable energy. The law forced regulated electric utilities such as PacifiCorp to buy power from other, more efficient producers, if their cost was less than the utility's own "avoided cost" rate to the consumer. PURPA established a new class of generating facilities that receive special rate and regulatory treatment. Generating facilities in this group are known as qualifying facilities (QFs), and fall

to East Control Area (ECA), DC Intertie costs) and its calculations of certain power cost components (*i.e.*, Jim Bridger coal costs, Jim Bridger heat rate, hedging costs, market caps in the GRID power cost model).

a. Qualifying Facilities Contract Costs

97 The single most significant NPC issue in this case is PacifiCorp's unilateral modification of the WCA methodology to change the allocation of costs attributable to the Company's obligations under its QF power purchase agreements (PPAs) in the west control area states.[137] QFs refer to energy generation facilities from which a utility must purchase power under PURPA, at a rate that equals the utility's "avoided cost." The avoided cost is that cost which the utility avoids by not having to build or otherwise acquire an equivalent resource. Under PURPA, the states are delegated authority to determine the applicable avoided cost for each utility.

98 Under the current WCA methodology, the costs of QFs are allocated to the states on the basis of the physical location of the QF. Costs from QFs that are physically located in Washington are allocated to Washington rates. Costs from QFs in Oregon and California are not allocated for recovery from Washington ratepayers. This so-called "situs allocation" of QF costs was part of PacifiCorp's WCA proposal in Docket UE-061546 that was approved by the Commission in that case in 2007, with limited revisions.[138] It is important to understand that situs allocation, thus applied, has nothing to do with the physical flow of power across state boundaries. Situs allocation under the WCA methodology concerns only the assignment of costs.[139] Washington ratepayers remain responsible for paying for all of the power they use, but any power attributed to an Oregon or California QF, is priced at market rates, not

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into two categories: qualifying small power production facilities and qualifying cogeneration facilities. A small power production facility is a generating facility of 80 MW or less whose primary energy source is renewable (hydropower, wind or solar), biomass, waste, or geothermal resources. A cogeneration facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy.

[137] Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in scattered sections of 15, 16, 42, and 43 U.S.C.).

[138] *See WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶ 53 (June 21, 2007).

[139] See Gomez, Tr. 486:8-488:10.

the higher prices from QF production in those states. At the same time, however, Washington rates include 100 percent of the costs PacifiCorp incurs in buying power from Washington QFs, whether higher or lower than market rates, even though power from Washington QFs arguably is also serving load in Oregon and California.

99 PacifiCorp now proposes to abandon situs allocation for QF contracts and to allocate a portion of the higher costs of Oregon and California QF contracts to Washington.[140] Staff argues this is a significant change considering that 74 percent of QF power for 2014 comes from contracts PacifiCorp entered in the last five years at avoided cost rates for Oregon and California.[141] Staff argues that, as a result of policy choices that Oregon and California have made in implementing PURPA, the costs of these contracts results in net power cost that are significantly higher than would be the case were the same contracts re-priced at Washington's avoided cost rates.[142] Staff calculates that the Company's proposal increases Washington net power costs by $10.7 million.[143]

100 In this case, even though PacifiCorp recognizes the need to show "'tangible and quantifiable benefits to Washington' before the resources can be included in rates"[144] the Company simply makes the vague assertion that the Oregon and California QFs provide "undifferentiated generation to serve Washington load and [enable] PacifiCorp to avoid generation costs that would otherwise be incurred in the absence of these resources."[145] The Company adds that:

> Other benefits of renewable QF contracts include system diversity, increased transmission reliability, reduced environmental impact, and promotion of Washington's energy policies to mitigate greenhouse gas emissions and climate change.[146]

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[140] PacifiCorp Initial Brief ¶ 54.

[141] Staff Initial Brief ¶ 65.

[142] *Id.* ¶¶ 81-82.

[143] *Id.* ¶ 65.

[144] PacifiCorp Initial Brief ¶ 59.

[145] *Id.*¶ 60.

[146] *Id.*

Concerning PacifiCorp's focus on "undifferentiated generation to serve Washington load," however, Mr. Gomez testified during his cross-examination that the relationship between situs allocation and Washington load is not a material consideration.[147] Situs allocation is about "the assignment of costs" and "doesn't speak to what the actual flow of power is."[148]

101 Staff's opposition, thus, does not focus on the question whether QFs in Oregon and California provide "undifferentiated generation" in the WCA. Instead, Staff's focus is on the underlying purpose of the WCA's situs allocation of QF cost. That purpose, according to Staff, is to recognize that the three state's approaches to implementing PURPA's QF requirements are different, having different policy goals, achieving different ends, and resulting in different costs. It is Staff's position that Washington ratepayers should not be made responsible for the higher costs of QF power in Oregon and California that are the result of those states' environmental policies and their choices in implementing PURPA to promote those policies.

102 Although PURPA is a federal law, its implementation was left largely in the hands of individual states. Under PURPA, states may determine the specific conditions under which utilities must take the power, including the maximum amount of power, the duration of contracts, and the rate that utilities must pay (*i.e.,* the avoided cost). In other words, individual state utility commissions can determine to a substantial extent the amount and types of QF power that utilities subject to their jurisdiction must purchase.

> In implementing state policies such as providing incentives for the development of renewable energy states may, for example, increase the maximum amount of power that must be purchased under a QF contract and also set the avoided cost at a higher level. Other states may elect to implement such policies by other means, placing less emphasis on PURPA and relying more on approaches such as establishing enforceable renewable portfolio standards.

103 The Revised Protocol recognizes QF contracts as "state resources" along with demand-side management (DSM) programs and portfolio standards, all of which

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[147] Gomez, Tr. 486:8-487:4.

[148] *Id.*

depend on individual state policy.[149] The rationale for situs allocation, as recognized in both the Revised Protocol and the WCA, is to insulate states from policy decisions made by other states. Situs allocation under the Revised Protocol is limited to the costs associated with DSM programs and renewable portfolio standards. The WCA method, however, treats all state resources, including QF contracts, the same way.

104 PURPA requires states to implement FERC's regulations for investor-owned utilities.[150] FERC's regulations establish numerous guidelines that "shall, to the extent practical, be taken into account" when establishing QF avoided cost rates, but otherwise delegate to each state the discretion to choose the actual methodology and calculation of appropriate QF contract rates.[151] Staff argues that the Commission and the Oregon commission have used their discretion by adopting different and unique approaches for determining the price a utility must pay for power from a QF.

105 In Washington, all investor-owned utilities must file a standard contract tariff for purchases from QFs with a generation capacity of one megawatt or less.[152] QFs may then accept a purchasing utility's standard offer contract, without filing a bid, regardless of the generation technology used.[153] The Commission has approved tariffs implementing a standard offer contract for all three investor-owned utilities.[154] Avista's tariff applies to QFs with a generating capacity of one MW or less. PacifiCorp's Schedule 37 applies to QFs of two MW or less. PSE's tariff applies to QFs of five MW or less.[155]

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[149] *See WUTC v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-050684, Order 04, ¶ 32 (April 17, 2006).

[150] 16 U.S.C. § 824a-3(f).

[151] 18 C.F.R. § 292.304(e). These factors include the ability of the utility to dispatch the QF, the expected or demonstrated reliability of the QF, and the duration of the utility's contract with the QF. The Company, therefore, is wrong to argue that PURPA mandates the precise methodology for determining avoided cost prices for QF contracts. *See* Duvall, Exh. No. GND-7CT at 8:8-9.

[152] WAC 480-107-095(1).

[153] WAC 480-107-095(2).

[154] Staff Initial Brief ¶ 73.

[155] *Id.*

106 The Commission does not require a specific standard contract length but a utility may enter into QF contracts for up to a 20-year term or longer.[156] The companies' tariffs include published standard contract term lengths.[157] PSE's standard contract extends for 10 years. PacifiCorp's standard contract includes an avoided cost price stream over 10 years, but states expressly that the listed avoided costs are fixed for only five years.

107 Tariffs offering standard contract rates for QF power in Washington are based on avoided costs, as are utility offers to QFs of larger capacity generation. The companies are required to file annually a schedule of estimated avoided costs. The estimates are based on the utility's most recent project proposals received under a Request for Proposals, estimates included in the company's current Integrated Resource Plan, the results of the utility's most recent competitive bidding process, and projected market prices for power.[158]

108 Oregon is more prescriptive in its QF contracting policies. Oregon utilities are required to offer standard offer contracts to QFs with a generation capacity up to 10 MW, not 1 MW as in Washington. Oregon has a maximum standard contract term of 20 years, similar to that in Washington. In Oregon, however, a QF is allowed to select fixed pricing for the first 15 years, but is required to select a market price option for the remaining 5 years. Oregon requires different methods for different utilities depending on whether the utility is in a resource-deficient or sufficient position. PacifiCorp, for example, is required to use monthly on- and off-peak forward market prices to calculate avoided costs when the company is in a resource sufficient position.[159]

109 The Oregon commission requires PacifiCorp to offer three pricing options for standard offer contracts: 1) the Fixed Avoided Cost Price Method; 2) the Banded Gas Market Index Option; and 3) the Gas Market Index Method. PacifiCorp's filed tariffs

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[156] WAC 480-107-075(3).

[157] Staff Initial Brief ¶ 73.

[158] WAC 480-107-055.

[159] Staff Initial Brief ¶ 78.

in Oregon reflect all of these options in Schedule 37.[160] Oregon has also developed very detailed requirements for negotiation of non-standard contracts with QFs greater than 10 MW. These include specific procedures and timelines for contract negotiation; pricing provisions that distinguish between "legally enforceable" and "as available" contract terms; contract terms to address matters such as termination, scheduling of outages and availability during emergencies; and the impact on the calculation of avoided costs for integration costs for renewable resources, line losses and the treatment of transmission and distribution-related savings and costs.[161]

110 *Commission Determination:* PacifiCorp's proposal to allocate the costs of Oregon and California QF contracts to Washington is tantamount to asking that we abandon the WCA methodology and adopt the Revised Protocol methodology for this purpose.[162] The Commission, however, has flatly rejected the Revised Protocol as an inter-jurisdictional cost allocation method for use in this state.[163] Moreover, the Commission embraced the WCA methodology, which explicitly excludes Oregon and California QF contract costs, as "a solid foundation for determining the resources that actually serve load in Washington" because it is based "on the generation resources that are actually used to keep the west control area in balance with its neighboring control areas."[164] There is nothing in the record of this case that shakes this foundation.

111 Furthermore, situs allocation is fair. Like Oregon and California, Washington has adopted policies favoring and encouraging renewable energy. However, the approaches of the three states are different. Oregon and California have implemented PURPA to carry out policies favoring renewable energy that has resulted in 74 percent of PacifiCorp's QF power for 2014 coming from contracts PacifiCorp entered in the last 5 years at avoided cost rates for Oregon and California. Washington policy makers have relied less on PURPA and more on renewable portfolio standards and greater use of tax-related incentives to promote renewable energy development in this

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[160] *Id.* ¶ 79.

[161] *Id.* ¶ 80.

[162] *Id.*¶ 73.

[163] *Id.* ¶ 49.

[164] *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶ 53 (June 21, 2007).

state.[165] Washington's policies are paid for by Washington taxpayers or ratepayers, as this state's policy makers determine. Absent a regionally negotiated alternative arrangement, Oregon's and California's renewable energy policies should be paid for by the taxpayers and ratepayers of those states, as determined by their policy makers.

112 PacifiCorp has recognized Washington's broad, tax-based approach to support the development of distributed generation as being superior to policy approaches such as embodied by PURPA that place on ratepayers the full burden of "energy sources that are not cost effective for customers."[166] PacifiCorp's proposal, in this context, is tantamount to an effort to relieve Oregon and California ratepayers from higher cost burden that results from those states' implementation of PURPA to promote distributed generation by shifting a portion of those costs to Washington ratepayers. This would be fundamentally unfair when, according to PacifiCorp "the most 'effective and fair approach' [to this end is] a public subsidy such as the Washington community solar tax credit."[167]

113 Staff's analyses show that there is a significant financial impact on Washington state ratepayers due to the different QF policies in Oregon and Washington. The Oregon and California QF contracts result in net power costs that are significantly higher than would be the case if they were priced at Washington avoided cost rates.[168] Again, as argued by Staff, absent a regionally negotiated alternative arrangement, each state should bear the costs of its respective renewable energy policies.

114 There simply is no basis in the record of this case to justify changing allocation methods for QF contract costs as PacifiCorp proposes. We determine that QF contract costs should continue to be allocated using the approved WCA methodology.

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[165] *See e.g.*, RCW 82.04.294; RCW 82.16.110-30; RCW 82.08.956-.957, 962-963; and RCW 82.12.956-957, 962-963.

[166] Exh. No. DCG-7CX (UTC Report on the Potential for Cost-Effective Distributed Generation in Areas Served by Investor Owned Utilities in Washington State, Docket UE-110667 at 28 page 31 of the exhibit (October 7, 2011) (citations to internal quotes: Comments of PacifiCorp at 5, 14-15 (July 15, 2011).

[167] *Id.* PacifiCorp also refers in this comment to the federal renewable energy production tax credit that has been famously successful in promoting the development of wind energy projects in Washington, Oregon, and other states.

[168] Staff Initial Brief ¶ 81.

b. Imputed Sales

115 When the Commission adopted the WCA methodology, it conditioned its approval by imputing benefits to PacifiCorp's west balancing authority area or west control area (PWCA) to reflect market sales to Pacificorp's east balancing authority area or east control area (PACE) considering transmission availability and market prices.[169] This imputation adjustment allowed for the "indirect inclusion of eastside benefits and costs if purchases or sales between the control areas are economic."[170] In other words, the WCA methodology recognized that, even though there is limited transmission capability between PWCA and PACE, the east control area takes advantage of some of the resources that are allocated to the west control area. The condition imputing benefits was consistent with the Commission's overall belief that the WCA methodology is

> straightforward and easy to understand. It is flexible enough to accommodate allocation of indirect benefits and costs when they are quantified and demonstrated.[171]

116 PacifiCorp agreed to this imputation adjustment when the WCA was approved, albeit with the understanding that the WCA "monitoring committee" could "review the eastern market adjustment in the future and propose modifications, if appropriate."[172]

117 The Company proposes in this case to exclude the imputed value of sales from PWCA to PACE even though it modeled over $51 million in such sales for the 2014 rate year. The net power cost impact of this exclusion is an increase of $300,000 compared to the Commission-approved WCA method that imputes these market sales.

118 PacifiCorp argues that the adjustment is not straightforward and requires the development of additional data not otherwise required for the WCA method. It also asserts that the assumptions underlying the adjustment are no longer valid today.

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[169] *WUTC v. PacifiCorp,* Docket UE-061546, Order 08 ¶45 (June 21, 2007).

[170] *Id.* ¶ 47.

[171] *Id.* ¶ 56.

[172] *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶ 45 (June 21, 2007).

PacifiCorp states that a 40 percent reduction of transfer volumes from Jim Bridger to account for competition from other generators selling power to PACE is part of the calculation of the imputed sale.[173] The Company implies that changes in the markets serving PACE, notably the development of significant wind resources in Wyoming since 2007, somehow impact this part of the calculation.[174] The Company fails, however, to establish how, or to what extent this is so.

119 In addition, PacifiCorp argues that wheeling costs have changed since 2007 such that the imputed sale calculation "fails to account for the wheeling costs that PacifiCorp would actually incur if it were engaging in the fictional transaction."[175] Again, however, the Company offers no analysis demonstrating that the impact of this change is of such nature or extent to support elimination of, or an adjustment to, the imputed sale from the net power cost calculation.

120 PacifiCorp's argument essentially boils down to the point that: "Because the imputed sale is entirely fictional, there is no realistic basis for imputing the sale nor is there any reasonable foundation for modeling the sale."[176] Staff states, however, that "the adjustment recognizes the limited transmission path between control areas and the material benefit received by the ECA from resources paid for by WCA customers."[177] This was the basis for imputing the sale in the first place and is today a valid reason to retain it.

121 *Commission Determination:* We agree with Staff that this imputation adjustment should be retained because it recognizes the material benefit received by the PACE customers from resources paid for by PWCA customers considering the limited transmission path between PacifiCorp's two control areas. This was an integral part of the WCA allocation methodology that the Commission approved in Docket UE-061546. Nothing in this regard has changed. While there might be some basis to change the calculation of the imputed sale to reflect changed conditions such as those

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[173] PacifiCorp Initial Brief ¶ 69.

[174] *Id.*

[175] *Id.* ¶ 70.

[176] *Id.*

[177] Staff Initial Brief ¶ 88.

to which PacifiCorp refers, the Company failed to establish or propose specific changes that might be appropriate. We therefore reject the Company's unilateral, unsupported proposal to remove this imputed sale.

c. DC Intertie Costs

122 PacifiCorp has a long-standing agreement with the Bonneville Power Administration (BPA) that provides transmission capacity on BPA's Direct Current (DC) Intertie from the Nevada-Oregon Border market hub to the Buckley substation. PacifiCorp has BPA network transmission service from the Buckley substation to its system loads, which enables it to make power purchases at the Nevada-Oregon Border market hub. PacifiCorp proposes to include the costs of the DC Intertie in NPC in this case. The effect of including this transmission right and associated modeled purchases at the Nevada-Oregon Border hub is to increase NPC by $1.1 million.

123 Boise White Paper and Staff propose to remove these costs from NPC. Boise White Paper relies on the Commission's decision in PacifiCorp's 2010 general rate case disallowing these costs.[178] The Commission there determined that no benefits were likely to materialize from the transmission capacity under the contract during the rate year. In other words, the Commission found the contract was not, at the time, used and useful. The Company's failure to include Nevada-Oregon Border market hub contracts in the GRID model was a key factor supporting the Commission's conclusion.[179]

124 PacifiCorp argues that the DC Intertie contract is used and useful because it facilitates the Company's transactions at the Nevada Oregon Border market hub, which have consistently occurred over the last five years and are expected to continue into the future.[180] Although the Company has always transacted at the Nevada-Oregon Border market hub, the power cost model on which PacifiCorp relies (*i.e.*, the Generation and Regulation Initiatives Decision, or GRID, model) did not previously include this hub

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[178] Deen, Exh. No. MCD-1CT 6:8-14; *WUTC v. PacifiCorp*, Docket UE-100749, Order No. 06 ¶¶ 148-52 (Mar. 25, 2011).

[179] *See* Gomez, Exh. No. DCG-1CT at 20:15-18.

[180] Duvall, Exh. No. GND-7CT at 44:1-6.

in its topology.[181] The Company, however, has modified GRID's topology, and now these transactions are specifically captured in the power cost model.[182] Mr. Gomez testifies this "results in $970,410 ($34.81 per MWh x 27,880 MWh) of power sales to serve customers in the Company's central Oregon load pocket."[183]

125 Staff argues, however, that because including the DC Intertie adds approximately $1.1 million in transmission costs, its costs outweigh its benefits. Mr. Gomez testifies, too, that because the power purchased through the Nevada-Oregon Border market hub serves only Oregon loads, there is "no demonstration of tangible or quantifiable benefit to Washington ratepayers.[184]

126 PacifiCorp argues that the DC Intertie benefits Washington customers by taking advantage of the load diversity between California and the Pacific Northwest to provide valuable energy and capacity benefits.[185] Staff's analysis fails to account for the capacity benefits.[186] PacifiCorp states that without the DC Intertie the Company would be required to obtain another capacity resource.[187] PacifiCorp points out that the DC Intertie is included in the preferred portfolio in the Company's Integrated Resource Plan (IRP) and is an integral piece of the Company's overall transmission system.[188]

127 PacifiCorp argues finally that the fact that the DC Intertie serves Oregon loads does not reduce the benefits provided to Washington customers because the use of the DC Intertie frees other resources to serve Washington customers.[189] PacifiCorp makes the related point that the Company cannot terminate the DC Intertie contract because it is

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[181] *Id.* at 43:14-19. GRID is a highly complex, proprietary power cost model that PacifiCorp uses to calculate its power costs in all of the states in which the Company operates.

[182] *Id*.

[183] Gomez, Exh. No. DCG-1CT at 20:20-21:4.

[184] *Id.* at 21:11-19.

[185] Duvall, Exh. No. GND-7CT at 43:7-13.

[186] *See* Gomez, Exh. No. DCG-1CT 20:21-21:4.

[187] Duvall, Exh. No. GND-7CT 44:7-13.

[188] *Id*.

[189] *Id.* 45:8-19.

linked to the Company's AC Intertie agreement that provides significant benefits in the West control area.[190] Mr. Duvall testifies on this point stating that the AC Intertie:

> Provides considerable value by allowing for sales and purchases at the [California Oregon Border] market [hub]. For example, in the Company's direct filing, the west control area benefits from $53 million in wholesale sales revenues from the COB market. [191]

128 *Commission Determination:* The Commission disallowed the costs of this transmission facility in PacifiCorp's 2010/2011 general rate case.[192] This was based on evidence, including "the absence of NOB contracts in the Company's GRID model"[193] indicating, in the Commission's view, that the transmission capacity was not providing benefits to Washington customer and, hence, should not be considered used and useful in the test year or the rate year.

129 In this case, however, the evidence shows that Nevada –Oregon Border hub contracts are included in the GRID model, overcoming the threshold problem on which this issue turned, in part, in the Company's 2010/2011 general rate case. PacifiCorp demonstrates direct benefits from the DC Intertie contract that are only slightly less than the contract's costs. More importantly, the Company points to significant indirect benefits that result from this contract because of its link to the Company's AC Intertie that facilitates sales at the COB market hub.

130 We find on the basis of the more robust evidence that PacifiCorp presents in this case, relative to that presented in the 2010/2011 proceeding, that the Company's DC Intertie contract with BPA is used and useful. It should provide during the rate year direct and indirect benefits that more than offset its costs to Washington customers. We determine, therefore, that a proportionate share of the costs of the DC Intertie should be allowed in rates.

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[190] PacifiCorp Initial Brief ¶ 88.

[191] Duvall, Exh. No. GND-7CT at 46:12-16.

[192] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 152 (March 25, 2011).

[193] *Id.* ¶ 149.

d. Jim Bridger Coal Costs

131 PacifiCorp fuels its Jim Bridger plant largely with coal supplied by an affiliate mine, Bridger Coal Company (BCC).[194] Boise White Paper recommends a $4.3 million reduction to the Washington revenue requirement associated with the fuel costs for the Jim Bridger coal generation plant. This recommendation is based on Washington Commitment 12 in the settlement agreement that formed the basis for the Commission's approval of PacifiCorp's acquisition by MEHC in 2006.[195] Commitment 12 provides that "MEHC and PacifiCorp agree to use asymmetrical pricing for affiliate charges or costs . . . if a readily identifiable market for the goods, services or assets exists, and if the transaction involves a cost of more than $500,000."[196]

132 PacifiCorp states that the Commission has allowed PacifiCorp to purchase coal from BCC at the actual, prudent costs of production, plus a return component on the investment in the Bridger mine, limited to PacifiCorp's current authorized rate of return, for many years.[197] Under this approach, if BCC earns a margin over PacifiCorp's authorized rate of return, it must credit this margin back to PacifiCorp through a reduced transfer price.[198] PacifiCorp witness Ms. Crane testifies that the Commission has never applied Washington Commitment 12 to transactions between BCC and PacifiCorp as a result of the merger, and argues that there is no need to do so now.[199]

133 Washington Commitment 12 is designed to protect customers by preventing cross-subsidization of affiliates by customers. Boise witness Mr. Deen argues that his

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[194] Crane, Exh. No. CAC-1CT 4:7-12.

[195] In the Matter of the Joint Application of MidAmerican Energy Holdings Company and PacifiCorp, d/b/a Pacific Power & Light Company for an Order Authorizing Proposed Transaction, Docket No. UE-051090, Order 08 at App. A, p. 16 (Mar. 10, 2006) (Commitment Wa. 12).

[196] *Id.*

[197] *Id*. 5:18-21; s*ee, e.g., WUTC v. Pac. Power & Light Co.,* Cause No. U-86-02, 78 P.U.R.4th 84 (Sept. 19, 1986).

[198] Crane, Exh. No. CAC-1CT 6:1-2.

[199] Crane, Exh. No. CAC-1CT 6:9-12; *see also* PacifiCorp Initial Brief ¶ 77.

adjustment is necessary to ensure "ratepayers are protected from affiliate abuse by the Company paying an unreasonable price which would allow the affiliate and parent corporation to achieve above market profits."[200] However, Ms. Crane testifies there is no risk of cross-subsidization or affiliate abuse related to BCC coal because of the unique regulatory treatment consolidating BCC with PacifiCorp for ratemaking purposes.[201] Under the accepted approach, BCC is not treated as an affiliate at all; it is treated as if PacifiCorp itself were mining the coal.[202]

134 *Commission Determination:* Boise White Paper presents no compelling reason to alter the long-standing practice of treating BCC's operations as if they were conducted by the Company without regard to the affiliate relationship. This practice was in place for many years prior to MEHC's acquisition of PacifiCorp, and it has continued without challenge in this jurisdiction until now despite the existence of Washington Commitment 12 for more than half a dozen years. Limiting the costs the Company incurs to maintain and use this fuel to prudent costs of production, plus a return component on the Company's investment in the Bridger mine, capped by PacifiCorp's current authorized rate of return, adequately protects ratepayers from potential abuse from an affiliated transaction. We reject Boise White Paper's recommended adjustment to Jim Bridger Coal costs.

e. Jim Bridger Heat Rate Adjustment

135 PacifiCorp's turbine upgrade at its Jim Bridger 2 facility went into service in May 2013. The Company proposes to include the facility as a post-test period pro forma adjustment to rate base, which we approve in a separate discussion below. The turbine upgrade's total estimated cost is approximately $31 million, a portion of which will be paid for by PacifiCorp's Washington ratepayers.

136 Boise White Paper argues that if the Commission allows the turbine upgrade to be included in rates, then it should adjust the Jim Bridger 2 unit heat rate to reflect the efficiency gain that the upgrade provides. "Failure to include the efficiency improvements in rates now is inequitable. Customers should not be forced to bear the

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[200] Deen, Exh. No. MCD-1T 21:23 – 22:2.

[201] Crane, Exh. No. CAC-1CT 6:16-19.

[202] *Id*.

costs without including some measure of the benefits."[203] Boise White Paper acknowledges, however, that "[t]he main benefit of the upgrade is that it will increase Bridger's generating capacity by about 12 MWs with no additional fuel requirements."[204] PacifiCorp argues that "[t]his increased generation is included in the NPC calculation so customers are receiving this benefit directly."[205]

137 Boise White Paper's proposal asks the Commission to make an exception to the previously approved methodology for calculating heat rates. PacifiCorp consistently uses a 48-month historical period to calculate heat rates in its thermal plants as well as to normalize other attributes of these plants in its filing.[206] PacifiCorp witness Mr. Duvall refers in this connection to forced and planned outage rates, which he says are related to heat rates:

> The efficiency of steam units tends to decline over time as components degrade. During a major plant overhaul, even without a turbine upgrade, worn seals are replaced, heat exchange surfaces are cleaned, and a portion of the unit's efficiency losses can be recovered. [207]

138 PacifiCorp uses a 48-month period to calculate heat rates so that normalized heat rates reflect the conditions present under most of a typical, four-year major planned outage cycle. According to Mr. Duvall, using only the period immediately following an outage would understate the normalized heat rate:[208]

> A unit's heat rate changes over time and improvements are expected after any major overhaul. Boise's adjustment relies on heat rate data immediately following a planned outage where the turbine was upgraded and the unit underwent normal maintenance. Boise's upgraded heat rate is therefore based on the unit's new and clean

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[203] Boise White Paper Initial Brief ¶ 61.

[204] *Id*. ¶ 62.

[205] Duvall, Exh. No. GND-7CT at 49:21-5:1.

[206] *Id.* at 47:14-16.

[207] *Id.* at 47:18-48:2.

[208] *Id.*

> condition, which is not reflective of the heat rates over the course of a full outage cycle, and thus not normal.[209]

139 Mr. Duvall also testifies that Boise's proposed change is one-sided, failing as it does to recognize conditions at plants can change to increase, as well as decrease heat rates. He gives the example of the installation of pollution control equipment at Jim Bridger Unit 3, which had the effect of increasing the heat rate.[210] Mr. Duvall concludes:

> This adjustment contradicts a clear, straightforward, and long-standing methodology, and is applied in a one-sided manner. For those reasons, the Commission should reject the adjustment.[211]

140 *Commission Determination:* Mr. Duvall offers a satisfactory response to Boise White Paper's suggestion that we should order an ad hoc exception to PacifiCorp's long-standing practice of using a 48-month average to recognize changes in heat rates, and to otherwise normalize attributes of the Company's thermal resources. The benefits of the Jim Bridger turbine upgrade will be recognized in rates immediately in the form of increased energy from the plant reflected in the NPC in this case and over time as the efficiency gained acts as a moderating factor in the normalization process. We reject Boise White Papers recommended adjustment.

f. Hedging Costs

141 Public Counsel recommended through Mr. Coppola's testimony that the Commission not allow PacifiCorp's hedging cost in the calculation of 2014 (*i.e.*, rate year) NPC. Mr. Coppola testifies that "this cost of nearly $3 million to Washington customers is speculative since it will change daily as the market price changes."[212] Hence, Public Counsel argued, the cost fails the known and measurable test.[213]

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[209] *Id.* at 49:10-16.

[210] *Id.* at 48:3-10 and 50:6-12.

[211] *Id.* at 50:15-17.

[212] Coppola, Exh. No. SC-1CT at 6:22-7:2.

[213] *Id.* at 19:14-19.

142 PacifiCorp argues that the Commission rejected an adjustment very similar to what Public Counsel proposes here in PSE's 2009 rate case.[214] In that case, the Commission said that "hedging is an appropriate tactic to manage fuel cost risk [and] it is appropriate for the cost of hedges to be included in power cost rates."[215] PacifiCorp also notes the Commission's approval of its own hedging practices in the Company's 2006/2007 general rate case.[216] The Commission observed in the PSE case that "[w]hile it is true that the intrinsic value of hedges will vary with the actual cost of gas, this does not make hedging costs any less known and measurable than the market cost of gas" used to determine NPC.[217]

143 Citing these same authorities, Public Counsel in its brief acknowledges that "[t]he Commission has held that mark-to-market adjustment are known and measurable."[218] Public Counsel states that the calculation the Commission approved in the 2009/2010 PSE general rate case, comparing the Company's short-term forward gas purchases to the current forward gas price for the rate year in PSE's net power cost model, "seems to be similar to the calculation conducted by PacifiCorp in this case."[219] Public Counsel "recognizes that this issue is likely decided by the 2009 PSE order,"[220] but argues "the record in this case would support an alternate finding, should the Commission deem it appropriate."[221]

144 *Commission Determination:* We discuss the known and measurable standard in more detail below in a separate section of this Order.[222] It is sufficient to observe here that

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[214] PacifiCorp Initial Brief ¶ 73 (citing *WUTC v. Puget Sound Energy*, Dockets UE-090704 *et al.*, Order 11 ¶ 26 (Apr. 2, 2010)).

[215] *Id.* (citing Order 11 ¶ 153).

[216] *See WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶ 117 (June 21, 2007) (PacifiCorp's strategy of hedging electricity purchases is prudent).

[217] *WUTC v. Puget Sound Energy*, Dockets UE-090704 et al., Order 11 ¶ 154 (Apr. 2, 2010); *see also WUTC v. Puget Sound Energy*, Dockets UE-111048 et al., Order 08 ¶ 241 (May 7, 2012) (affirming treatment of hedging costs).

[218] Public Counsel Initial Brief ¶ 64.

[219] *Id.*

[220] *Id.* ¶ 67.

[221] *Id.*

[222] *See infra* ¶ 200.

the use of forward prices in modeling net power costs for the rate year has become standard practice in general rate cases and is recognized as an exception to the known and measurable standard.[223] The Commission recognizes, too, that this applies in connection with hedging costs:

> While it is true that the intrinsic value of hedges will vary with the actual cost of gas, this does not make hedging costs any less known and measurable than the market cost of gas that is an input to the AURORA model.[224]

145 We see no reason to depart from the Commission's prior determinations and they govern here. We reject Public Counsel's proposed adjustment to remove hedging costs from NPC.

g. Market Caps in GRID

146 PacifiCorp, like other electric utilities the Commission regulates, offsets its overall NPC by making short-term sales at each of the market hubs to which it has transmission access. Insofar as relevant here, these are sales at the Mid-Columbia and California-Oregon Border market hubs. Unlike any other Northwest utility, however, PacifiCorp places caps on the potential market sales in its power cost model. This is necessary, PacifiCorp argues, because the GRID power cost model on which it relies uses static pricing, does not account for intra-hour changes in market conditions and thus fails to account adequately for market illiquidity.[225] PSE and Avista, in contrast, use the AURORA power cost model, which uses dynamic pricing that inherently recognizes changes in market liquidity. The Company states that it has used market caps as a part of GRID's basic design since the introduction of the model.[226]

147 PacifiCorp argues that market caps are necessary to constrain and limit GRID's default assumption of unlimited market depth for short-term firm sales.[227] According

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[223] *WUTC v. Puget Sound Energy*, Dockets UE-090704 et al., Order 11 ¶ 26 (Apr. 2, 2010).

[224] *Id.* ¶ 154. PSE and Avista use the AURORA power cost model.

[225] PacifiCorp Initial Brief ¶ 95.

[226] *Id.* ¶ 94 (citing Duvall, Exh. No. GND-7T at 31:10-13).

[227] *Id.* (citing *Id.* at 30:9-18).

to PacifiCorp, this means that GRID does not consider load requirements, actual transmission constraints, market illiquidity, or assumptions about market prices that would preclude sales at the static forecast price.[228] PacifiCorp argues that without market caps to account for these actual market constraints, GRID may model transactions and impute sales revenues that are not actually available to the Company.

148 PacifiCorp states, in addition, that the market caps are based upon the Company's actual average historical sales levels during the preceding four-year period and are, therefore, reasonably representative of the Company's actual operations.[229] Boise White Paper argues, however, that by basing market caps on the average energy sold over the entire monthly peak or off-peak period for the previous four years and applying this average to every hour of the test period modeling, PacifiCorp fails to account for "many hours in the historical period in which the actual sales exceeded the average sales value for a particular time period."[230] Boise White Paper argues that basing the market caps on average historical sales has the effect of understating the level of off-system sales revenues because the level of modeled sales is "far below" what the Company has historically achieved and "profitable sales levels . . . are abnormally lower than historic actuals."[231]

149 Mr. Duvall, however, testifies that:

> Any deterministic hourly production dispatch model that balances and optimizes a pro forma period on an hourly basis will model a lower volume of transactions than actually occurs. The GRID model produces a lower volume of transactions because it balances loads and resources on an hourly basis with perfect foresight. On an actual basis, system balancing is a long process that involves numerous updates of load and resource balances due to changes in load forecasts, the availability of thermal units, hydro conditions, etc., up to the actual time of delivery. Additionally, products available in the market are not

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[228] *Id.*

[229] *Id.* (citing Duvall, Exh. No. GND-7CT at 36:8-10).

[230] Boise White Paper Initial Brief ¶ 51 (citing Deen, Exh. No. MCD-1CT at 11:26-12:3).

[231] *Id.* ¶ 52 (citing *Id.* at 12:19-20)

> always a good fit to balance resource requirements, which also leads to higher actual volumes.[232]

Mr. Duvall also criticizes Boise White Paper's argument that actual sales at the Mid-Columbia and California-Oregon Border hubs are significantly greater than the sales modeled in GRID, supporting the removal of market caps. Mr. Duvall says it is important to look at the hubs individually:

> The Company's filed NPC study, which includes market caps, modeled only three percent fewer COB [California-Oregon Border] sales than the actual 48-month average used to develop the market caps. Boise's proposal to eliminate the market caps altogether resulted in the model producing 139 percent *more* COB sales than the 48-month average.[233]

Mr. Duvall testifies additionally that the Company's NPC study includes fewer sales than historically experienced at the Mid-Columbia hub due to expiring contracts that have resulted in "nearly one million less MWh or Mid-C [Mid-Columbia] hydro generation available" to the Company.[234]

150 Mr. Duvall's illustration comparing actual sales at the California-Oregon Border hub over various periods to GRID results, with and without market caps shows that with market caps the model produces results that are more comparable to actual results than it does without market caps.[235] During periods of lower sales, GRID tends to overstate off-system sales volumes. During periods of higher sales, the sales volumes GRID produces are uniformly understated. However, GRID without market caps significantly overstates off-system sales at all sales volumes.

151 Mr. Duvall's comparison also shows results based on a method adopted by the Oregon Commission that Boise White Paper urges in the alternative.[236] The Oregon method uses a market cap based on the highest of the four years of historical data for

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[232] Duvall, Exh. No. GND-7T at 33:6-14.

[233] *Id.* at 33:19-34:3.

[234] *Id.* at 34:8-12.

[235] *Id.* at 35:1-36:7.

[236] Boise White Paper Initial Brief ¶ 59.

a given monthly period, rather than the average of four values.[237] This approach, according to Boise White Paper, "would move the Company's power cost modeling somewhat closer to the Company's actual yearly sales level."[238] The method adopted in Oregon overstates sales to a lesser degree, but still uniformly results in sales that are higher than actuals except at the very highest volumes of sales.

152 *Commission Determination:* The conflicting evidence on this issue demonstrates both the complexity and deficiencies of the GRID model on which PacifiCorp relies for forecasting net power costs and the related impracticality of attempting to "fine-tune" such a model on the basis of quantitative analyses that demonstrate no particular advantage of one proposal relative to another insofar as accuracy is concerned. PacifiCorp's approach appears to understate volumes of sales and revenues. Boise White Paper's approach tends to overstate both. The Oregon Commission method appears to be more balanced, but still consistently overstates PacifiCorp's off-system sales.

153 Boise White Paper makes a persuasive case that PacifiCorp's use of market caps in the GRID model produces results that are far from ideal. Mr. Deen's analysis shows that the methodology PacifiCorp uses to reflect real world, wholesale power market constraints on its ability to make off-system sales does not produce modeled results that accurately reflect actual results. On the other hand, Mr. Duvall's analysis shows that Boise White Paper's proposal to bring the Company's long-standing use of market caps in the GRID model to an end also fails to produce such results. Indeed, it appears it may be even less accurate than the current model.

154 On balance we find the weight of the evidence tips to the favor of maintaining the status quo. While market caps may result in understated levels of off-system sales, either at individual hubs or in aggregate, simply eliminating market caps, as Boise White Paper advocates, does not appear to lead necessarily to more accurate results. Indeed, eliminating market caps with no other refinements to the GRID model could lead to even more inaccurate results in the opposite direction. We therefore will not

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[237] Deen, Exh. No. MCD-1CT at 17:8-11.

[238] Boise White Paper Initial Brief ¶ 59 (citing Deen, Exh. No. MCD-1CT at12:11-13; 17:19-21).

require PacifiCorp to eliminate its use of market caps in the GRID model to project NPC in this case.

155 We nevertheless find sufficient evidence to support a finding that the GRID model is not fully satisfactory, at least in its treatment of off-system sales. We conclude the model's structure and method of forecasting such sales should be thoroughly reexamined at the time of PacifiCorp's next general rate proceeding. Indeed, we find it necessary to take the unusual step of directing the Commission's regulatory staff to engage with PacifiCorp, and others if appropriate, to find a better, more accurate approach to this problem.

156 We also express concern that the GRID model may suffer broader infirmities. The GRID model is proprietary to PacifiCorp. It is neither as straightforward nor transparent as the AURORA model, on which Washington's other investor-owned utilities rely. The complexity and potentially controversial inner-workings of the GRID model evident in this proceeding lead us to determine that we should require PacifiCorp to engage with Staff, Public Counsel, and others, to discuss whether the GRID model can be made more transparent, or should be replaced, to increase the Commission's level of confidence in PacifiCorp's net power cost forecasting. We expect that the Company, together with Staff and the stakeholders, will keep us apprised of the progress made in such a collaborative at the appropriate time. At a minimum, we expect PacifiCorp and Staff to address the continued use of GRID in its next general rate filing and encourage others to do so as well.

D. PCAM

157 The Company, through Mr. Duvall, proposes a Power Cost Adjustment Mechanism (PCAM) to collect or credit the differences between the actual net power costs incurred to serve Washington customers and the amount of net power costs collected from Washington customers through rates.[239] PacifiCorp argues that it "needs a PCAM in Washington to address its substantial NPC variability, which is caused primarily by factors outside the Company's control."[240]

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[239] *See generally* Duvall, Exh. No. GND-1CT at 26:1-49-2.

[240] PacifiCorp Initial Brief ¶ 100.

158 PacifiCorp contends a PCAM is needed because:

> In the Company's 2006 rate case, the Commission concluded that the "Company is subject to significant power cost variability . . . sufficient to warrant consideration of a PCAM as a means to accommodate this variability in ratemaking."[241] In that case, the NPC variability ranged from $26 to $48 million.[242] The Company's NPC variability is now approximately $67 million—far exceeding the level the Commission already concluded was sufficient to warrant a PCAM.[243]

The evidence from PacifiCorp's 2006 general rate case *might* be relevant today if the comparison the Company draws to "NPC variability [that] is now $67 million," was an accurate comparison, but it is not. Indeed, it is misleading. It depends on a Staff response to a PacifiCorp data request in which Mr. Gomez compares the Washington jurisdiction NPC variability, of which there was evidence presented in the 2006 rate case, to West control area variability during a recent period.[244] This is the proverbial comparison of apples to oranges. It appears that the predicate for Staff's testimony, that PacifiCorp faces power cost variability sufficient to justify a PCAM, is flawed. Because Mr. Gomez compares a West control area number to a Washington jurisdiction number, his analysis leading to Staff's support for PacifiCorp's assertion of power cost variability that establishes "need" for a PCAM is simply misplaced.

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[241] *Id*. (citing *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 ¶ 71 (June 21, 2007)). We note the irony of PacifiCorp's argument later in its initial brief, with reference to this same order, that "a conclusion reached by the Commission more than six years ago does not mean it is still relevant today." *Id.* ¶108 (citing Coppola, Exh. No. SC-1CT 38:20-21).

[242] *Id*. (citing Order 08 ¶ 68).

[243] *Id*. (citing Gomez, Exh. No. DCG-6CX).

[244] In support of the $67 million figure and its quoted assertion of power cost variability, PacifiCorp cites to Exhibit No. DCG-6CX, which is Mr. Gomez's response on behalf of Staff to a PacifiCorp data request. The response refers to Mr. Duvall's Exhibit No. GND-4 and underlying workpapers that are not in evidence. The $67 million figure is found in the workpapers, apparently showing power cost variability "above and below a mean of $507 million." Mr. Gomez's response demonstrates that he compared the $67 million figure to Staff's $26 million dollar figure in the 2006 case and on that basis determined in this proceeding that "the Company faces variability in NPC sufficient to justify a [PCAM]." Gomez, Exh. No. DCG-6CX. During cross-examination, however, Mr. Gomez testified that the $67 million figure is not Washington allocated NPC but, rather, is for the entire west control area. TR. 497:19-498:5 (Gomez).

159 In point of fact, the best evidence in the record concerning the question of power cost variability is Mr. Duvall's Exhibit No. GND-4. This evidence shows a steady decline in the variability of Washington allocated NPC from 2007 through 2011, from $15,584,000 (14.6 percent) in 2007 to $6,724, 000 (5.5 percent) in 2011. Mr. Coppola's Exhibit No. SC-16 provides similar data and results, reporting a further decline in 2012 to NPC variability in Washington of only $934,000 or less than 1.0 percent. Mr. Deen offers corroborating evidence in his testimony.[245] Thus, a valid comparison of PacifiCorp's experience with NPC variability in Washington today to the $26 million NPC variability in 2006, which was about 30 percent of Washington allocated NPC that year, brings dramatically into question whether PacifiCorp does, in fact, face a degree of power cost variability that warrants consideration of a PCAM at this time.

160 Boise White Paper argues that the relatively little variability in NPC in Washington during recent annual periods does not justify a PCAM because actual NPC always vary from normalized NPC for many reasons, including weather, load, market prices and resource performance.[246] According to Boise White Paper, "these are not abnormal, unusual, or extraordinary events" and in the absence of such events, the Commission previously has rejected a PCAM as an appropriate response.[247] Boise White Paper argues that "[t]he current record is . . . devoid of such evidence."[248]

161 Staff, Public Counsel, and Boise White Paper all oppose PacifiCorp's proposed PCAM for the additional reason that it is contrary to what the Commission has established in prior PacifiCorp cases and elsewhere as being a proper, basic design for such a mechanism. Staff, through Mr. Gomez, specifically opposes the Company's proposal because it does not contain sharing bands or a dead band, contrary to Commission precedent.[249]

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[245] Deen, Exh. No. MCD-1CT at 26:8 (Table 2-NPC Rates vs. Actual).

[246] Boise White Paper Initial Brief ¶ 79.

[247] *Id.* (citing *WUTC v. PacifiCorp,* Docket Nos. UE-050684 and UE-050412, Order 03 ¶ 92 (April 17, 2006)).

[248] *Id.*

[249] Gomez, Exh. No. DCG-1CT at 5:15-6:7.

162 Public Counsel witness Mr. Coppola testifies similarly that the proposed PCAM's design is flawed, requiring significant modifications including dead bands, sharing bands, a sufficient surcharge/refund trigger amount, appropriate reporting requirements and, possibly, an adjustment to the Company's return on equity. Public Counsel argues also that PacifiCorp's proposal is inadequate because it fails to allow sufficient review of deferrals under the PCAM.[250] Mr. Coppola testifies that a robust annual review process would enable a thorough prudence review of all cost items included in PacifiCorp's power cost deferrals. This review should occur annually, regardless of whether a refund or surcharge has been triggered.[251]

163 Boise White Paper, through Mr. Deen, also opposes the proposed PCAM because it would permit dollar-for-dollar recovery of all variability in NPC, from any cause, without dead bands or sharing bands to allocate risk properly between the Company and its customers. According to Mr. Deen, any potential PCAM should have properly constructed asymmetrical dead bands, a sharing mechanism and an earnings test.

164 Mr. Duvall dismisses dead bands and sharing bands as "poor regulatory policy" that penalizes the Company because net power cost variability is largely outside of its control and, therefore, bands do not motivate the utility towards greater efficiency.[252] Mr. Duvall testifies that:

> Deadbands and sharing bands do not work as intended and instead produce random windfalls or losses to the utility and its customers, undermining predictable and fair utility rates and regulation.[253]

165 Staff points out, however, that all of the Company's other state regulatory commissions have approved PCAMs for PacifiCorp that contain dead bands, sharing bands, or both.[254] Moreover, the Commission has approved PCAMs for Avista and

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[250] Public Counsel Initial Brief ¶ 102 (citing Coppola, Exh. No. SC-1CT at 42:10-14).

[251] *Id.* (citing Coppola, Exh. No. SC-1CT at 43:6-11).

[252] Duvall, Exh. No. GND-1CT at 31:20-32:5.

[253] *Id.* at 32:5-7.

[254] These mechanisms have been in place for some time. In rejecting a PCAM proposal in PacifiCorp's 2005/2006 general rate case, in part because the proposal did not include dead bands or sharing bands, the Commission noted that

PSE that both have dead bands and sharing bands. The Company's proposal in this case is at odds with all of the mechanisms approved by this Commission and the utility regulatory commissions in each of the Company's other jurisdictions.

166 Staff states that the Commission has expressly rejected in prior orders the Company's argument concerning its regulatory policy relative to power cost adjustment mechanisms:

> Power cost recovery mechanisms should also apportion risk equitably between ratepayers and shareholders. In striking that balance, we consider risks already allocated through the normalization process, a utility's financial condition and other circumstances affecting a utility's ability to recover its prudent expenditures. Dead bands and sharing bands are useful mechanisms, not only to allocate risk, but to motivate management to effectively manage or even reduce power costs.[255]

Staff argues that the Company continues to ignore these Commission directives on PCAM design.

167 PacifiCorp argues that unlike the circumstances it faced in 2006, its power cost variability is now symmetrical, not asymmetrical, making dead bands and sharing bands unnecessary.[256] Mr. Gomez testified on cross-examination, however, that this

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> PacifiCorp has filed power cost adjustment mechanisms with varying risk sharing features in at least four other states in its service territory: California, Oregon, Utah, and Wyoming. PacifiCorp's PCAM in Oregon does not include a dead band, but includes two sharing bands, such that customers bear 70 percent of costs up to $100 million, and 90 percent of costs over $100 million. PacifiCorp asserts these sharing bands are appropriate, as the Company has the option of annually resetting its net power costs on a forecast basis through a Transition Adjustment Mechanism.
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> PacifiCorp recently agreed to, and the Wyoming Commission recently approved, a revised PCAM for PacifiCorp as a part of a rate case settlement. PacifiCorp's Wyoming-revised PCAM includes a dead band of $40 million above and below the base, as well as three significant sharing bands.

WUTC v. PacifiCorp, Docket UE-050684, Order 04 at ¶¶ 94-95 (April 17, 2006).

[255] *Id.* ¶ 96.

[256] PacifiCorp Initial Brief ¶¶ 108-09.

is simply irrelevant.[257] He said that the need for dead bands and sharing bands does not turn on whether power cost variability is symmetrical or asymmetrical. This factor is considered only in the design of the bands.[258]

168 A more salient comparison between PacifiCorp's 2005/2006 PCAM proposal and its proposal here concerns PacifiCorp's claim that it needs the PCAM to address the volatility of power costs. The record in this case fails to support PacifiCorp's asserted need for a PCAM on the basis of the degree of volatility the Company faces, as previously discussed. In addition, as was the case in 2006, the record here

> does not show that current power cost volatility is due to extraordinary events. Unlike the PSE and Avista power cost adjustment mechanisms, which were designed, in part, to address changes in power costs due to the unprecedented volatility in energy markets during 2000-2001, the proposed PCAM is not tailored to address short-run cost changes due to extraordinary or unusual events.[259]

169 *Commission Determination:* Staff sums up its principal arguments in opposition to PacifiCorp's proposed PCAM, with the observation that it does not oppose the Company having such a mechanism in place, but it must be properly designed in accordance with the explicit direction the Commission has given PacifiCorp in the past. Staff concludes that PacifiCorp's failure to do so means that "the real obstacle to a PCAM is the Company's insistence on a mechanism that is not properly designed."[260]

170 We agree with Staff's analysis on this issue. Indeed, the Company's proposal here is even more at odds with the direction the Commission has given PacifiCorp than its proposals in prior cases that have been rejected. Contrary to express Commission direction, and in contrast to the power cost adjustment mechanisms approved in other PacifiCorp jurisdictions, the Company's proposal here includes neither dead bands nor sharing bands. These are critically important elements that provide an incentive

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[257] Gomez, Tr. 493:3-12.

[258] *Id.*

[259] *WUTC v. PacifiCorp*, Docket UE-050684, Order 04 ¶ 92 (April 17, 2006).

[260] Staff Initial Brief ¶¶ 97-98.

for the Company to manage carefully its power costs and that protect ratepayers in the event of extraordinary power cost excursions that are beyond the Company's ability to control.

171 The Company's perfunctory response that dead bands and sharing bands are poor regulatory policy and that its power costs are increasingly beyond the Company's ability to control is simply not acceptable. Indeed, the first argument ignores that the regulatory authorities in every jurisdiction where PacifiCorp operates, including Washington, have determined that dead bands, sharing bands, or both are a necessary part of a PCAM.

172 The second argument suggests a loss of perspective on the Company's responsibility to manage its power costs using integrated resource planning, carefully structured hedging practices, conservation initiatives, and other means available to PacifiCorp and other utilities. It is certainly true that extreme weather events, unplanned outages of major generation sources, or other factors may result in extraordinary power cost variability that is beyond the Company's ability to control. Indeed, it is this sort of variability that power cost adjustment mechanisms are intended to protect against.[261] PacifiCorp, however, proposes a PCAM that would protect the Company from any risk of under-recovery, even that due to the ordinary variability in power costs due to normal and foreseeable changes in fuel costs, ordinary variance in hydro conditions, normal variations in weather, and so forth. As the Commission previously observed in connection with such a proposal: "This would mark a new and much expanded role for the PCA."[262] A properly designed PCAM includes dead bands and sharing bands so that the Company continues to bear some risk of under-recovery, and some opportunity to benefit from savings achieved via power cost management practices. Both this risk and this opportunity provide an incentive for the Company to use its best efforts to manage its power costs efficiently.

173 What PacifiCorp proposes here does not include any of the specific design elements the Commission has identified in its prior orders. Like Staff, we are open to consider a properly designed PCAM proposal that incorporates the appropriate balance

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[261] *WUTC v. Puget Sound Energy, Inc.,* Dockets UE-060266 and UG-060267, Order 08 ¶ 20 (January 5, 2007).

[262] *Id.*

between the Company and ratepayers. Yet, the Company's proposal in this case really is nothing more than a request for a power cost tracker and true-up mechanism that will guarantee the Company full recovery of its power costs on a continuing basis. We are not prepared to embrace such a mechanism and, therefore, reject PacifiCorp's proposed PCAM.

E. Rate Base

174 We must resolve three related issues concerning rate base:

- Whether to use end-of-test-period (EOP) or the average of monthly averages (AMA) method to determine rate base.
- Whether to allow post-test period pro forma adjustments to rate base.
- Whether the Commission should expressly authorize the Company to make an expedited rate filing (ERF) to update its rate base at the time it files its next Commission Basis Report (CBR).

What principally ties these issues together is the question of regulatory lag and how best to address it while protecting ratepayers.

1. End of Period Rate Base

175 PacifiCorp filed this case using electric plant in service balances at EOP levels, rather than the AMA levels used in previous cases.[263] The Company proposed using EOP rate base to minimize regulatory lag by reflecting rate base balances that are likely to exist during the rate year and to address the Company's persistent under-earning.[264]

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[263] McDougal, Exh. No. SRM-6T at 26:10-11.

[264] *Id*. 26:13-17.

176 Staff observes that the Commission has expressed its preference for the AMA method.[265] According to Staff, "this upholds the matching principle of ratemaking because AMA balances accurately match rate base over the course of the test year with revenue and expenses incurred over that same period."[266] Staff says EOP rate base balances are less than optimal unless there are corresponding end of period adjustments to revenues and expenses, which the Company did not make in its filing.[267]

177 Staff acknowledges, however, that "utilization of average rate base [is] not cast in stone."[268] Staff identifies circumstances in which the Commission may determine that EOP rate base is an appropriate regulatory tool to accommodate for:

- Abnormal growth in plant.
- Inflation or attrition.
- Regulatory lag.
- Failure of utility to earn its authorized rate of return over an historical period.[269]

Staff "agrees there is reason to address the impacts of regulatory lag on PacifiCorp."[270] Staff, however, would have the Commission reject PacifiCorp's use of EOP rate base to address the problem and proposes an alternative means of doing so, as we discuss later.

178 Public Counsel agrees with PacifiCorp that end-of-period rate base valuation is an appropriate tool to use to address regulatory lag, and supports using end-of-period

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[265] Staff Initial Brief ¶ 164 (citing Erdahl, Exh. No. BAE at 6:16-7:2).

[266] *Id*.

[267] Erdahl, Exh. No. BAE at 7:17-19 (citing, *WUTC v. Washington Natural Gas Company,* Cause No. U-80-111, Third Supplemental Order at 5-7 (September 24, 1981)).

[268] *Id.*

[269] Staff Initial Brief ¶ 165. *See WUTC v. Wash. Nat. Gas Co.,* 44 P.U.R. 4th 435, 438 (Sept. 24, 1981) (*Washington Natural Gas*).

[270] *Id*. ¶170.

rate base in this case.[271] Mr. Dittmer testifies that end-of-period valuation reduces regulatory lag by approximately six months over the average-of-monthly-averages (AMA) method traditionally used by the Commission.[272]

179 Public Counsel addresses Staff's concern over the use of EOP rate base without corresponding end of period adjustments to revenues and expenses. Mr. Dittmer proposes two such adjustments. First, he proposes to annualize depreciation expense based on end-of-period Plant in Service values. The impact of this adjustment is to raise PacifiCorp's retail jurisdictional revenue requirement by approximately $520,000.[273] PacifiCorp accepted Mr. Dittmer's adjustment in its rebuttal testimony.[274]

180 Mr. Dittmer's second recommendation is for a corollary adjustment to annualize revenue levels associated with end-of-period numbers of Washington-jurisdictional customers being served.[275] PacifiCorp does not dispute conceptually the idea of annualizing revenues, but it disagrees with Mr. Dittmer's approach of calculating revenues based on customer count at the end of the test period. PacifiCorp argues this

> [f]ails to account for all the factors that are used to normalize revenues, namely loads, including seasonal loads, that are associated with changes in customer counts. Failing to account for load changes results in a mismatch between customer counts and customer usage and has complicated, and potentially controversial, consequences for setting rates.[276]

PacifiCorp argues further that it does in fact annualize revenues in this case, using "long-established and well-understood ratemaking practices to normalize test year revenues. Public Counsel recognizes that this matter is not entirely clear cut and, though it continues to advocate adoption of Mr. Dittmer's end-of-period revenue

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[271] Dittmer, Exh. No. JRD-1T at 2:16-19, 4:19-5:2, and 8:12-10:2.

[272] *Id.* at 6:1-7.

[273] Dittmer, Exh. No. JRD-1T at 10:6-21.

[274] McDougal, Exh. No. SRM-6T at 10:17-11:8.

[275] Public Counsel Initial Brief ¶¶ 26-27.

[276] PacifiCorp Initial Brief ¶ 147 (citing Steward, Exh. No. JRS-7T at 22:14-19 and Tr. 398:19-399:2 and 399:20-400:16).

adjustment, suggests it may be appropriate for the Commission to require a more refined calculation by the Company in a future rate case.[277]

181 *Commission Determination:* The Commission historically has tolerated some degree of regulatory lag in its ratemaking practice, recognizing that it is a factor in encouraging utilities to operate efficiently. During recent periods, however, the impacts of regulatory lag on the ability of PacifiCorp and other utilities to earn their authorized revenue requirements have contributed to what the Commission has described as a "current pattern of almost continuous rate cases."[278] Considering this, the Commission stated:

> This pattern of one general rate case filing following quickly after the resolution of another is overtaxing the resources of all participants and is wearying to the ratepayers who are confronted with increase after increase. This situation does not well serve the public interest and we encourage the development of thoughtful solutions.[279]

182 There are a host of factors, both specific and general, that contributed to the development of this pattern, beginning with the Western energy crisis that unfolded during 2000-2001. It is a fair generalization to say that the dynamic conditions in the U.S. and world economies since that time have had a material effect in producing this pattern.

183 Facing similar circumstances during the period of extraordinary inflation during the 1970's and early 1980's,[280] the Commission said that regulatory lag "has long been a concern of both the utilities and their regulators" that can have a "deleterious effect," and that "as regulators we have the responsibility to mitigate that effect to the extent

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[277] Public Counsel Initial Brief ¶¶ 29, 30.

[278] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049 (consolidated), Order 08 ¶ 507 (May 7, 2012).

[279] *Id.*

[280] *WUTC v. Wash. Nat. Gas Co.*, Cause No. U-80-111 44 P.U.R. 4th 435, 437 (Sept. 24, 1981) *(*"We have in the past decade witnessed a proliferation of rate filings and most filings have brought the differences over rate base into sharp focus.").

possible."[281] The Commission recognized the use of EOP rate base as one means to address this problem:

> It is not a misstatement to say that the weight of authority, both in the administrative and judicial branches, favors average over year-end rate base on the premise that in normal economic times average rate base is more realistic and projects more accurately the cost of plant that produces the revenue under investigation. However, there is sizeable and well-recognized authority that in an abnormal and less stable economic climate year-end rate base may be more appropriate and should be used to balance out the financial problems caused by abnormal and uncertain economy.[282]

The Commission most recently revisited this issue in a PSE rate case and approved the use of EOP rate base as a means to address the company's financial problems that were attributed to regulatory lag and resultant under-earnings.[283]

184 In this case, there is a need to address at least some of the impacts of regulatory lag on PacifiCorp. We determine that an appropriate response to address these impacts in this case is approval of PacifiCorp's use of EOP rate base. We accept, too, the adjustment Public Counsel proposes to recognize end-of-period depreciation. The Company agrees with this adjustment.

185 We reject for purpose of this case Public Counsel's proposed adjustment to end of period revenues. We agree that it is necessary for such an adjustment to be made, but we have questions concerning Public Counsel's approach in this case. PacifiCorp's normalization of revenues from the test period may accomplish the same purpose. At a minimum, the Company's normalization of revenues adequately resolves the matter for purposes of setting rates. We find that it would be unduly complicated in the context of this case to fully explore and resolve the impacts that adoption of Public Counsel's approach would have in terms of the production factor adjustment, allocation issues, and rate spread. In any future case in which PacifiCorp, or another

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[281] *Id.* at 438.

[282] *Id.* at 437.

[283] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-130137 and UG-130138 (consolidated), Order 07 ¶¶ 46-48 (June 25, 2013).

party, proposes EOP rate base, we would expect to see a more fully developed record and a more refined approach to ensuring there is not a resulting violation of the matching principle.

2. Major Capital Plant Additions

186 In another effort to address regulatory lag related to the timely recovery of infrastructure investments and to help narrow the gap between the costs incurred to serve Washington customers and the costs recovered in customer rates, the Company proposes including in rate base the capital costs of five major projects placed in service after the end of the historical test period:

- Soda Springs Fish Passage ("Soda Springs"), in service October, 2012; final closeout costs May 2013.[284]
- Swift Fish Collector ("Swift"), in service November, 2012; final closeout costs May 2013.[285]
- Prospect In-Stream Flow/Automation system ("Prospect"), in service December, 2012; final closeout costs June 2013.
- Merwin Fish Collector ("Merwin"), expected in-service date February, 2014.
- Jim Bridger Unit 2 turbine upgrade, in service May, 2013.

187 No party opposes including Soda Springs, Swift, or Prospect costs as pro forma adjustments. Staff affirmatively recommends adding to rate base the capital costs incurred as of January 11, 2013, for the Soda Springs Fish Passage, the Swift Fish Collector, and the Prospect In-Stream Flow/Automation addition. [286] Mr. McGuire testifies for Staff, however, that any costs, including project closeout costs, projected beyond this date should be excluded from rate base.[287] Staff bases its adjustment on

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[284] Williams, Exh. No. JMW-1CT at 4:18-20.

[285] *Id.* at 4:5-10.

[286] McGuire, Exh. No. CRM-1T at 10:18-23.

[287] *Id.*

the gross plant value less one year of accumulated depreciation for these three facilities.[288]

More specifically, Ms. Williams testifies that Staff recommends allowing:

- The total $60,608,221 of Swift Fish Collector project costs incurred through December 2012 should be included in rate base, including $38,935,266 as a *pro forma* adjustment.[289]
- The $73,422,320 of project costs incurred through December 2012 in connection with the Soda Springs Fish Passage should be placed into rate base as a *pro forma* adjustment.[290]
- The $10,090,905 of project costs incurred through December 2012 for the Prospect In-stream Flow/Automation system should be placed into rate base as a *pro forma* adjustment.[291]

PacifiCorp provided updated actuals in its rebuttal testimony showing the amounts as follows:

Project	System Cost	Washington Allocated
Swift Fish Collector	$39,394,153	$8,913,514
Soda Springs Fish Passage	$73,257,863	$16,575,683
Prospect In-stream Flow/Automation system	$10,984,971	$2,485,513

188 Staff contests PacifiCorp's proposed recovery of O&M costs for Swift. Staff argues that while the Company does have operational data for Swift, they are for only a little over "half a year," through June 2013.[292] PacifiCorp acknowledged at the hearing

[288] *Id.*

[289] Williams, Exh. No. JMW-1CT at 13:16-21.

[290] *Id.* at 17:20-18:2.

[291] *Id.* at 21:9-14.

[292] Staff Initial Brief ¶ 150 (citing Tallman, Exh. No. MRT-2T at 4:7).

that it "missed the mark" in its initial O&M expense forecast.[293] However, relying on eight months of actual data, the Company cut its projection of annual O&M expense for Swift from $756,000 to $344,000.[294] Staff contends this updated O&M expense for Swift, albeit based on actual data, remains largely an estimate.

189 Staff and Public Counsel object to including the other two projects in rates—the Merwin Fish Collector and the Jim Bridger Unit 2 turbine upgrade—because they were not in service within a very short time after the end of the test year. Staff would apply a "bright line" cut-off date of January 11, 2013, the day PacifiCorp filed this case. Staff would approve recovery of costs incurred for Soda Springs, Swift and Prospect as of this date, but not any final closeout costs incurred afterward. Staff recommends, in addition, disallowance of O&M expense associated with the Merwin and Swift fish collectors as not known and measurable.[295]

190 Public Counsel supports Staff's proposal that we establish a bright-line rule, but would extend the date in this case to February 28, 2013. Public Counsel's date apparently is based on PacifiCorp's initial responses to discovery that "provided the capital additions incurred as of February 2013."[296] Mr. Coppola recognizes, however, that

> [t]he Commission has adopted a modified historical test year approach whereby it has included certain revenue, costs and capital additions after the end of the historical test year if the amounts were known and measurable. The Commission has adopted this regulatory approach to minimize regulatory lag and avoid adopting a forecasted test year approach.[297]

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[293] Tallman, Tr. 331:7-332:20.

[294] Tallman, Exh. No. MRT-2T at 4:4-14.

[295] McGuire, Exh. No. CRM-1T 11:17 – 12:12. The Swift Fish Collector went into service in November 2012, before Staff's and Public Counsel's proposed cut-off dates. Staff supports inclusion of the Swift Fish Collector in rate base, but objects to the O&M expenses associated with the collector.

[296] Coppola, Exh. No. SC-1CT at 22:22-23:1.

[297] *Id.* at 24:4-10.

191 Staff describes "Commission practice" in allowing pro forma adjustments as "historically highly variable":

> Previous Commission decisions have ranged from rejecting all pro forma plant additions, to allowing pro forma plant additions that were projected to be placed into service well into the rate year.[298]

Mr. McGuire concludes:

> The historically wide range for Commission consideration of pro forma plant additions demonstrates that there is no set rule for the establishment of a cut-off date. The lack of a set rule enables Staff considerable flexibility in developing its recommendation.[299]

Staff's recommendation is that no pro forma rate base addition costs be allowed if the plant is not in service by the time the Company filed its case and the costs are not "known and measurable."[300] Staff apparently considers a cost as known and measurable only if it is an actual cost recorded on the Company's books and auditable at the time of the Company's filing.[301] Staff also states the criterion that "the pro forma addition to rate base must have no offsetting factors."[302]

192 Staff's reason for urging use of the Company's general rate case filing date as a bright line cutoff date for pro forma adjustments is that this

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[298] McGuire, Exh. No. CRM-1T at 7:1-4 (citing *WUTC v. Puget Sound Energy, Inc*., Dockets UE-060266 and UG-060267, Order 08 ¶¶ 49-52 (January 5, 2007) and *WUTC v. Avista Corporation, Dockets* UE-090134, UG-090135 and UG-060518, Order 10 ¶¶ 80-81 (December 22, 2009). We note that the Commission's rejection of pro forma plant additions in the PSE case was not based on historic rate year ratemaking principles, but rather was because PSE's proposal included an extraordinary number of projects (*i.e.*, 6,000) including 20,000 line entries on the Company's books, making any audit all but impossible and, even more significant, the Commission found insubstantial the evidence offered in support of the adjustments. Order 08 ¶¶ 48-51.

[299] *Id*. at 7:9-12.

[300] *Id*. at 8:13-18.

[301] *Id*. at 10:2-8.

[302] *Id*. at 8:18-19.

> [a]llows Staff full use of the time allowed by statute to evaluate the adjustments without burdening the process, the record, and Staff's and the Commission's limited resources. Allowing pro forma plant additions that are placed into service subsequent to the filing of this rate case is tantamount to requiring a continuous audit during the pendency of the rate proceeding and requires Staff to analyze a continuously evolving case. This is an unreasonable and unnecessary expectation that compromises Staff's ability to perform a thorough analysis of the proposed adjustments and, in turn, fully assist the Commission in its evaluation of the issues.[303]

193 PacifiCorp placed the Jim Bridger Unit 2 upgrade in service in May 2013. There is no dispute that it is now used and useful and its costs are known and measurable. The upgrade improves the efficiency of the generating unit and the associated benefits are reflected in the Company's net power cost calculation.[304]

194 Focusing on prior practice with respect to the treatment of such investments in general rate cases, PacifiCorp observes that the Commission allows these types of adjustments when the offsetting factors are captured through NPC modeling, even if the facility enters service after the test period.[305] In PSE's 2009 general rate case, for example, the Commission approved a pro forma rate base adjustment related to a wind plant expansion that entered service 10 months after the end of the test period because it was a generation asset included in the NPC model. In a 2009 Avista general rate case, the Commission approved a pro forma rate base adjustment relating to a turbine upgrade and mechanical overhaul of a hydropower facility that were scheduled to be in service three months into the rate year and 18 months after the end of the test period.[306] The Commission found that the project costs were "sufficiently well established" and the turbine upgrade was included in the model used to develop the rate year's NPC.[307]

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[303] McGuire, Exh. No. CRM-1T at 9:10-18.

[304] PacifiCorp Initial Brief ¶ 116.

[305] *WUTC v. Puget Sound Energy*, Dockets UE-090704 et al., Order 11 ¶ 31 (Apr. 2, 2010).

[306] *WUTC v. Avista*, Dockets UE-090134 and UG-090135, Order 10 ¶¶ 12, 58, 80-81 (Dec. 22, 2009).

[307] *Id.* ¶ 81.

195 Similarly, PacifiCorp argues, the Jim Bridger Unit 2 upgrade entered service 11 months after the conclusion of the test period and seven months before the rate year, which is comparable to the timing in the Avista and PSE cases. In addition, the offsetting factors—the NPC benefits associated with the turbine upgrade—are accounted for in the Company's filing.[308] PacifiCorp argues it is consistent with past precedent and reasonable for the Commission to approve the inclusion of this generation resource in the Company's rate base.

196 The Merwin Fish Collector presents somewhat different circumstances. The Merwin project will allow fish to bypass the Company's three Lewis River dams in Washington.[309] The installation of this fish collector was necessary for the Company to secure a new FERC license, which will allow the Company to continue to operate the Lewis River dams for an additional 50 years.[310] The project's design was dictated and approved by federal regulators.[311] Because of this project, customers will continue to benefit from the Company's emission-free, low-cost hydropower generation, which is reflected in the Company's NPC model in this case.[312]

197 PacifiCorp said it plans to place the Merwin Fish Collector into service in phases. The first phase consists of a fish sorting facility. At the time PacifiCorp filed this case, the Company expected the sorting facility to be placed into service in May 2013, with a total projected cost of $14.6 million on a total-company basis. The second phase consists of the water attraction system that PacifiCorp expected to be placed in service in July 2013, with an estimated cost of $27.2 million on a total-company

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[308] *See* Duvall, Exh. No. GND-7CT 50:19-51:8.

[309] Tallman, Exh. No. MRT-1T 5:3-5.

[310] *Id.* 5:5-7; Tallman, Tr. 328:15-24.

[311] *Id*. 5:16 – 6:4. As required by its FERC license, the Company engaged in design reviews with parties to the Lewis River settlement agreement, which included the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, and the Washington Department of Fish and Wildlife. The final design was ultimately approved by the National Oceanic and Atmospheric Administration and the U.S. Fish and Wildlife Service. Although the Company provided input, these agencies have final authority over the design of the facility. Based on the design required by these agencies, the plant addition included in this filing for the Merwin Fish Collector is approximately $56.8 million on a total-company basis.

[312] Tallman, Tr. 328:15-24; *see also* J. Williams, Exh. No. JMW-1T 7:1-10 (other fish collectors provide same benefit).

basis. The third and final phase consists of a fish trap, lift and conveyance system that PacifiCorp expected to be placed in service in February 2014, with a total estimated cost of $15.0 million on a total-company basis.[313] There are no offsetting factors that would violate the matching principle because this is not a revenue producing asset.[314]

198 *Commission Determination:* Regulatory ratemaking involves, in many areas, the exercise of informed judgment. The reason Mr. McGuire found the Commission practice in accepting pro forma adjustments "highly variable" is because it is entirely appropriate for the Commission to make different determinations in different cases depending on the record in each individual case and the context in which the case is decided. While we will not take this occasion to expand on the point, a close reading of the Commission's general rate case orders over a significant period of time shows the Commission has consistently recognized the limits imposed by the "used and useful" and "known and measurable" standards while exercising the considerable discretion those standards allow in the context of individual cases.

199 Staff's idea that the Commission should have "a consistent and practical" "bright line" standard when evaluating what is "known and measurable" or "used and useful," though providing for some certainty in future application, is too rigid an approach. The Commission requires flexibility in most cases to exercise its informed judgment in ways that respond adequately and appropriately to the dynamic economic and financial circumstances that are characteristic of the utility industry and the general economy. Just as there are times when it is appropriate to depart from the preferred use of AMA rate base, as discussed above, there are times when it is appropriate to be more flexible in allowing post-test period pro forma adjustments and times when it is appropriate to be less flexible.

200 In sum, we reject the bright line cutoff dates proposed respectively by Staff and Public Counsel. We determine instead, for the reasons discussed below, that we should reject PacifiCorp's proposed pro forma adjustment that reflects the costs of the Merwin Fish Collector, but accept the costs of the Jim Bridger upgrade.

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[313] Tallman, Exh. MRT-1T at 6:6-13.

[314] McGuire, Exh. No. CRM-1T 10:10-20; J. Williams, Exh. No. JMW-1T 7:1-10.

201 In addition, we accept the pro forma additions for Soda Springs, Swift and Prospect, based on updated actuals as revised by the Company in rebuttal.

202 We also accept PacifiCorp's proposed recovery of O&M costs for the Swift facility. Eight months of operational data are adequate to support recovery of annualized costs at the level PacifiCorp proposes in its rebuttal testimony, $344,549.[315]

Merwin Fish Collector

203 We agree with Staff and Public Counsel that the pro forma adjustment PacifiCorp proposes for the Merwin Fish Collector should be rejected. The facility, at this juncture, is not used and useful nor will it be so until at least February 2014. Moreover, its costs are not known and measurable.

204 Although PacifiCorp claimed the facility would be put in service in phases, it is unclear what this means. It is a fish collector. Yet, at phases one and two the facilities described do not appear to be capable of performing this function. Indeed, Mr. Tallman testified in his rebuttal testimony in August 2013:

> Recent projections indicate the project will be substantially complete and used and useful in February 2014. Accordingly, the Company is currently projecting an in-service date during February 2014.[316]

Until the facility is fully functional, it cannot be said to satisfy the requirements of the Company's FERC license that covers the associated hydroelectric facilities. In other words, it is not used and useful today and will not be so for some time.

205 Even had the facility been shown to be in some sense functional at phase one or phase two, PacifiCorp did not put in the record any evidence of the actual costs incurred to complete these phases. The Commission previously has defined the known and measurable standard in detail:

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[315] Tallman, Exh. No. MRT-4C; *see also* Tallman, Exh. No. MRT-2T at 4:4-13.

[316] Tallman, Exh. No. MRT-2T at 2:12-13.

> The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be known to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations, and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be measurable. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are exceptions, such as using the forward costs of gas in power cost projections, but these are few and demand a high degree of analytical rigor.[317]

The evidence we have of the phase one and two costs is Mr. Tallman's initial testimony, but it includes only estimates that were available to him in January 2013 for project steps that were then expected to be complete in May and July, 2013. The only other cost evidence in the record are projections of phase three costs and total costs. These estimates do not satisfy the known and measurable standard.[318]

206 It follows from our rejection of the Merwin Fish Collector as a pro forma adjustment that we will not allow in rates the O&M costs associated with the facility. They are, in any event, estimates that we do not consider to be reliable.

<u>Jim Bridger Upgrade</u>

207 The Jim Bridger Unit 2 upgrade was placed in service in May 2013. Thus, it achieved used and useful status, and its costs became known and measurable before the date for response testimony. If Staff or another party wished to address the changed status of the facility and verify its costs, there was time to do so and, in any event, an interested party could have sought leave to file supplemental testimony on the subject once the necessary discovery and analysis was complete.

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[317] *WUTC v. Puget Sound Energy*, Dockets UE-090704 *et al*., Order 11 ¶ 26 (Apr. 2, 2010).

[318] We note that even when we asked PacifiCorp in a post-hearing bench request (*i.e.*, Bench Request 10) to produce actual numbers by project phase, the Company failed to provide a useful response.

208 There is no dispute in the record that the upgrade improves the efficiency of the generating unit.[319] The Company's economic analysis, which examined only the capacity benefits of the upgrade, demonstrated a $28.9 million customer benefit.[320] This evidence also stands unchallenged. Most significantly, no party challenged the inclusion of the benefits associated with the upgrade in the NPC calculation. Thus, the offsetting factors have been considered.

209 We determine that the costs of the Jim Bridger Unit 2 upgrade should be approved as a pro forma adjustment and authorized for recovery in rates.

3. ERF Proposal

210 Staff proposes through Ms. Reynolds that the Company be allowed to submit an ERF in 2014 within two months of the filing of its standard Commission-basis report (CBR).[321] The ERF would be based on an enhanced CBR using the same fiscal period as the CBR and using the authorized rate of return, revenue allocations, and rate design from this general rate case.

211 Staff provides a detailed description of the CBR enhancements it believes are necessary to make the report fully useful as a ratemaking tool.[322] Staff says its proposal would not require the Company to comply with the entire set of document filing requirements in WAC 480-07-510 that would otherwise apply to a general rate case, even if the filing seeks to increase rates by more than 3 percent.

212 Staff proposes to review the ERF with the goal of rates becoming effective within four to six months. The goal of a 2014 ERF is to bring 2013 capital additions and other cost changes into rates.

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[319] Ralston, Exh. No. DMR-1T 5:1-16.

[320] *Id.* 5:18-6:2.

[321] Reynolds, Exh. No. DJR-1T at 12:5-10.

[322] *See* Exhibit DJR-3.

213 Mr. Dittmer, testifying for Public Counsel, supports both the use of EOP rate base in this GRC and the ERF concept. He proposes certain modifications to Staff's proposal. Mr. Dittmer testifies:

- PacifiCorp should be required to calculate and post *all restating* adjustments adopted by the WUTC in its last general rate case GRC order prior to the ERF proceeding.
- PacifiCorp should be required to provide evidence that a reasonable effort has been undertaken to identify, quantify, and eliminate from the ERF test year cost of service material abnormal, non-operating and non-recurring transactions.
- Revenue relief to be granted through the ERF process should be limited to no more than 3 percent above existing base rates.
- PacifiCorp should be permitted to develop rate base utilizing end-of-ERF-test-year values for Plant in Service, Accumulated Depreciation and Accumulated Deferred Income Taxes.
- PacifiCorp should be permitted to file an ERF utilizing a non-calendar test year with no restriction as to the earliest date that such filing could be made.
- PacifiCorp should be permitted to file two ERFs before being required to make a GRC filing to further increase base rates. During the ERF proceeding(s) the Company would be prohibited from filing a general rate case.

214 Mr. Griffith testifies for the Company on this issue in Rebuttal. He says the Company "appreciates Staff's proposal," but complains that "the specifics are unclear."[323] He says, for example, that while it appears that Staff proposes allowing the Company to file an ERF that would include a rate increase of 3 percent or more, Staff does not describe how the requirements of WAC 480-07-505 would be waived or otherwise modified. Under this rule, proposed rate increases of 3 percent or more require a general rate case filing.

215 PacifiCorp states that its goal in this case is "to establish an appropriate baseline revenue requirement that gives the Company a reasonable opportunity to recover the

[323] Griffith, Exhibit No. WRG-1T at 9:4-5.

costs to serve its Washington customers."[324] Only then, in the Company's view, will it be appropriate to consider alternative ratemaking mechanisms such as the ERF. PacifiCorp notes that there is a pending rulemaking in Docket A-130355 that is expected to include rules governing ERFs.[325]

216 While Staff proposes the ERF as the answer to regulatory lag, PacifiCorp, in turn, proposes the use of "a streamlined separate tariff rider that would become effective once the Merwin Fish Collector is in service," as a means to address timely recognition of an asset that will be completed during the rate year.[326] The Company states that "[s]imilar approaches have been used in Oregon, California, and Utah to address capital projects coming on line during the rate year."[327]

217 *Commission Determination:* We find Staff's proposal of an ERF in this proceeding worthy of future consideration but premature in light of the Commission's initiation of Docket A-130355. The ERF concept has its merits to be sure, but we not prepared in this case to embrace it in its nascent form as a substitute for other, more fully developed and familiar approaches to addressing regulatory lag. In this case, we are approving PacifiCorp's use of EOP rate base, an approach the Commission has recognized for many years as an appropriate response to regulatory lag, particularly when associated with chronic under-recovery experience such as that of PacifiCorp during recent periods. We also are taking a more forward approach to allowing pro forma adjustments that capture the costs and benefits of upgraded production assets. This, too, is an approach with which the Commission has considerable experience and that has proven to be a useful means to reduce regulatory lag.

218 We recognize, too, that PacifiCorp is at best uneasy with the idea of relying on an ERF proposal that is not fully developed and may require amendments to, or express waivers of, existing requirements stated in WAC 480-07-505 and 510. PacifiCorp apparently recognizes that Staff cannot unilaterally decide that a rate filing that exceeds the 3 percent threshold defining a general rate case in WAC 480-05-505 need

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[324] PacifiCorp Initial Brief ¶ 126.

[325] *Id.*

[326] *Id.* ¶ 127.

[327] *Id.*

not meet the special filing requirements that WAC 480-07-510 requires in for general rate cases. Whether these rules should be amended is a proper subject to be addressed in the Commission's pending rulemaking in Docket A-130355.

F. Additional Adjustments

1. General Wage Increase - Pro Forma (Adjustment 4.3); Executive Compensation (Adjustment 4.16); and MEHC Officer's Compensation (Adjustment 4.17)

219 Staff and Public Counsel recommend various labor-related adjustments, including Staff's proposed adjustment to remove the escalation of annual incentive plan (AIP) expenses, and Public Counsel's proposed adjustments to reduce the amount of executive compensation and disallow expenses related to compensation for MidAmerican Energy Holdings Company officers. Mr. Wilson, testifying for PacifiCorp, says the Company's labor expenses are consistent with Commission precedent and reflect prudently incurred costs that benefit ratepayers. Accordingly, the Company asks us to reject the parties' recommendations.

220 Staff proposes removing a wage increase tied to PacifiCorp's Annual Incentive Plan (AIP).[328] While Staff does not oppose PacifiCorp's request for a wage increase tied to base salary, it argues that PacifiCorp's request for a parallel increase in the AIP portion of employee compensation should be rejected. Staff says that the incentive portion of compensation is always at risk and can be up or down based on annual performance. Staff argues it is therefore inappropriate to assume a particular level of incentive pay above test period amounts, as the Company has done in its adjustment.[329]

221 Staff further argues that if the AIP can only be adjusted upward by the non-union wage increase percentage, it becomes nothing more than another form of base salary increase and not an incentive reward for exceptional performance.[330] Staff's proposed

[328] Huang, Exhibit No. JH-1T at 10:6-15.

[329] Staff Initial Brief ¶ 178.

[330] *Id.*¶ 179.

adjustment would reduce the revenue requirement by $28,194 on a Washington-allocated basis.[331]

222 Mr. Wilson testifies in rebuttal that "the AIP is a critical piece of compensation that allows PacifiCorp employees the opportunity for their overall compensation to reach competitive market levels."[332] He says that pairing increases in base salary with parallel increases in the AIP is appropriate because these "two pieces are integral to a competitive market compensation package."[333] Mr. Wilson believes the Company's compensation package is reasonable and benefits ratepayers by encouraging superior employee performance. He notes that the Commission has approved this approach in the past and argues it should do so again.[334]

223 Mr. Coppola's testimony for Public Counsel includes three additional adjustments associated with labor and executive compensation. He testifies that the Commission should:

- Adjust employee reductions and cost savings through January 2013. The Company has undertaken a cost efficiency program that includes reducing employees. In its pro-forma adjustments, the Company included employee reductions as of October 2012. I have extended the employee reduction to January 2013 which reduces another 45 employees. The impact is to lower labor expense by $256,519.[335]

- Remove costs associated with compensation paid to MEHC officers. The Company has included a portion of the compensation paid to officers of MidAmerica Energy Holding Company (MEHC) in its labor expenses. The officers at MEHC do not appear to provide any direct

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[331] Exhibit No. JH-2 at page 5, line 16, column J.

[332] Wilson, Exhibit EDW-3T at 4:14-16.

[333] *Id.* at 4:16-18.

[334] *Id.* at 4:19-20. (citing *WUTC v. PacifiCorp*, Docket UE-100749, Order 06, ¶¶ 248-50 (March 25, 2011) ("By its very definition, incentive compensation is not a bonus or a level of pay in excess of the maximum compensation for a position. It is simply motivation for an employee to strive for the total compensation for his or her position by achieving certain individual and group goals. . . . The AIP is reasonable and its goals offer benefits to ratepayers.")).

[335] Coppola, Exh. No. SC-1CT at 9:10-15.

benefit to customers and are likely duplicative. Therefore, I recommend removing $131,493 of unnecessary expense.[336]

- Remove the above-market costs associated with the executive pay of the Company's top 25 highest paid positions. The Company does not have a formal process to set cash compensation levels for its executive management. I matched the total cash compensation of the top 25 positions at the Company to market compensation data provided through MarketPay. The result is that the cash compensation for this group of executives is $1.7 million above market. The portion applicable to Washington O&M, which I have disallowed, is $65,079.[337]

PacifiCorp agrees to the first of these three proposals by Mr. Coppola. Mr. Wilson says that the Company's revised revenue requirement at the rebuttal phase, "reflects January 2013 employee levels."[338]

224 Mr. Wilson testifies that Mr. Coppola's second adjustment fails to acknowledge that PacifiCorp's executive structure changed after the Company's acquisition by MEHC. Most significantly, the Chief Executive Officer (CEO) position was eliminated. This not only removed $750,000 in salary expense, it also allowed senior managers who were retained at PacifiCorp "to leverage, at significantly reduced expense, the expertise of the four MEHC officers whose compensation is allocate across PacifiCorp's business units."[339] By way of example, Mr. Wilson testifies that the highest level employees at PacifiCorp for human resources, information technology, and risk and insurance are managing director/director-level positions rather than vice presidents. These directors, he says, report directly to the MEHC Senior Vice President and Chief Administrative Officer.[340]

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[336] *Id.* at 9:16-21.

[337] *Id.* at 9:22-10-6. We note that later in his testimony, Mr. Coppola says the above-market compensation amount is $1.5 million. *Id.* at 34:4-5; s*ee also* Exh. No. SC-15.

[338] Wilson, Exhibit No. EDW-3T at 5:10-12 (referring to Exhibit SRM-7).

[339] Wilson, Exh. No. EDW-3T at 6:1-12.

[340] *Id.* at 6:13-18.

225 Mr. Wilson also disputes Mr. Coppola's third point. He states that other than for four executives whose compensation is set by MEHC's CEO, executive compensation at PacifiCorp is set "using the same well-defined, market-based approach used to determine the total compensation package for all employees."[341] He continues:

> [E]ach of the Company's positions is assigned a specific grade within PacifiCorp's overall salary structure. PacifiCorp collects market data for comparable positions at least annually using a number of sources of information, including the online tool "MarketPay.com." PacifiCorp uses this market data to determine the appropriate level of total cash compensation for each position, including the executive positions at issue. It then designates a certain portion of that compensation to be "at risk" for each grade.[342]

226 Mr. Wilson criticizes Public Counsel's review and analysis of this issue as being overly narrow and not comprehensive because it excludes important data necessary to "a complete and overall view/average of appropriate market compensation levels."[343]

227 *Commission Determination:* The Commission addressed the issue Staff raises concerning PacifiCorp's AIP as recently as PacifiCorp's 2010/2011 general rate case. There the Commission determined that:

> AIP is an appropriate method of implementing "incentive-based" compensation. PacifiCorp has chosen an overall structure of employee compensation that includes both a base salary and a certain portion that is "at-risk," or incentive compensation. By its very definition, incentive compensation is not a bonus or a level of pay in excess of the maximum compensation for a position. It is simply motivation for an employee to strive for the total compensation for his or her position by achieving certain individual and group goals.

Staff's argument in this case that we should now reverse this determination is not supported by convincing evidence. We reject Staff's recommendation.

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[341] *Id.* at 8:5-15.

[342] *Id.*

[343] *Id.* at 9:2-3.

228 We also find that Public Counsel's evidence falls short of what is required to order any adjustments to executive compensation in this case. The mid-point in executive compensation based on a single survey does not define the market. Market compensation encompasses a range of values. We have no evidence in this record concerning the upper and lower bounds of this range. Some employees will be compensated at levels higher than the mid-point; some will be compensated at levels lower than the mid-point. The fact that in PacifiCorp's case a larger number of executives are paid more than the mid-point indicated by Mr. Coppola's portrayal of data from MarketPay.com than are paid less than the mid-point does not mean individual employees are compensated at levels that are above what is reasonable.

229 Mr. Wilson's testimony on cross-examination by Public Counsel also demonstrates that the comparison on which Mr. Coppola relies in his Exhibit No. SC-15C gives an incomplete and perhaps misleading picture of PacifiCorp's executive compensation relative to the market.[344] For example, while Mr. Coppola's exhibit shows each of the four "named executive officers" compensated at above-market rates, the more detailed portrayal of data in Public Counsel's cross-Exhibit No. EDW-5CCX indicates that two are compensated above market and two below. This cross-examination exhibit also suggests the net of aggregate above-market and below-market compensation for the top 25 executives at PacifiCorp is only about one-third of the amount Mr. Coppola suggests in his response testimony.

230 Mr. Wilson's testimony successfully rebuts Public Counsel's recommendation that we eliminate from rates the allocated costs of certain MEHC officers because they "do not appear to provide any direct benefit to customers and are likely duplicative."[345] Mr. Wilson testifies:

> Before its acquisition by MEHC, PacifiCorp was led by a single Chief Executive Officer (CEO). Under the CEO, top-level senior business leaders headed up each of the Company's functional areas. As part of the MEHC acquisition, however, PacifiCorp was structurally realigned. The top-level CEO position was removed, along with all expenses related to that position (such as the CEO's annual salary of $750,000).

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[344] *See* Wilson, Tr. 379:14-383:20.

[345] Coppola, Exh. No. SC-1CT at 9:16-21.

> Some of the top-level senior business leader positions, however, were retained. Those business leaders are now able to leverage, at significantly reduced expense, the expertise of the four MEHC officers whose compensation is allocated across PacifiCorp's business units. If PacifiCorp were to seek this level of expertise and support in the open market, the expense would far exceed the allocation to rates reflected in PacifiCorp's requested revenue requirement.
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> The highest level employees at PacifiCorp for human resources, information technology, and risk and insurance are managing director/director-level positions rather than vice presidents. These directors report directly to the MEHC Senior Vice President and Chief Administrative Officer.

Thus, it appears the MEHC officers contribute directly to PacifiCorp as its most senior managers. This justifies the allocation of a portion of their compensation to the Company.

231 While we find the record in this case supports the determinations we make, we wish to emphasize as a general matter that executive compensation has reached levels at PacifiCorp, as well as at other utilities, that bring into question whether it is appropriate for ratepayers to continue to be called upon to pay them in full. It appears from the record in this case that PacifiCorp relies, at least in part, on market comparisons. While these may be widely accepted as part of executive compensation analysis, reliance on such data can lead to escalating salaries and benefits that are driven simply by the widespread use of such analyses.[346]

232 In its next case, as part of its burden of proof of the reasonableness of its operating expenses, we expect PacifiCorp to make a more robust showing than it did in this case to demonstrate how the Company makes executive compensation decisions. If the justification for executive salaries is based on comparing salaries in "peer" utilities,

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[346] *See, e.g.,* Gretchen Morgenstern, *Peer Pressure: Inflating Executive Pay*, N.Y. Times (Nov. 26, 2006); James Surowiecki, *Open Season*, The New Yorker, Oct. 21, 2013. As noted in these articles, this phenomenon is known as the "Lake Wobegon effect." In the fictional community of Lake Wobegon, "all children are above average." Basing executive salaries on peer reviews can lead to an "all executives are above average" fiction having real world effects.

we would expect a rebuttal to the criticism that such comparisons lead to inappropriate salary escalation over time. We expect, in addition, an analysis of just what value ratepayers receive from the day-to-day activities of the Company's top executives. The analysis we expect to see should include a realistic allocation reflecting the time each senior executive devotes principally to ratepayer interests and principally to shareholder interests. [347]

2. Working Capital (Adjustment 8.13)

233 Working capital is a measure of financial liquidity reflecting a company's ability to meet its day-to-day operational requirements inherent in a business cycle. It represents the amount of cash required to fund day-to-day operations of the Company, primarily for accounts receivable, inventories, materials and supplies, and other pre-paid expenses, net of short-term liabilities or credit provided by vendors and other creditors. Working capital is included in rate base and earns a return.

234 There are various approaches to calculating working capital for rate-making purposes, including lead/lag studies of cash needs and sources, days of O&M formula, and the current assets versus current liabilities balance sheet approach. The Commission evaluated these options in PacifiCorp's 2010/2011 general rate case and decided to use the balance sheet approach recommended by Staff, which is known as the Investor Supplied Working Capital (ISWC) method.[348]

235 Mr. Stuver testifies for PacifiCorp on this issue. He provides an overview of working capital and the investor-supplied working capital model approved in the prior GRC and proposes certain refinements in classifying balance sheet accounts "to properly measure investor-supplied working capital."[349] His proposed refinements relate to derivatives, pension, and other post-retirement benefits and frozen derivative

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[347] We recognize that these issues go beyond one utility. The Commission may determine that the topic of executive compensation is one for a more generic proceeding, at least an informal work session, where these issues can be discussed in a non-adjudicative setting.

[348] *WUTC v. PacifiCorp d/b/a Pacific Power and Light Company*, Docket UE-100749, Order 06, ¶¶ 283-296 (March 25, 2011).

[349] Stuver, Exh. No. DKS-1T at 2:3-9.

values.[350] According to Mr. Stuver's analyses, application of the investor-supplied working capital model, as he modifies it, results in a $21.5 million addition to Washington rate base and total ISWC of $28.5 million.[351]

236 Staff confirms Mr. Stuver's calculations:

> PacifiCorp . . . proposes two refinements to the calculation of ISWC for post-retirement pension benefits and derivatives. Both adjustments are conveniently made within a single calculation of ISWC. The ISWC methodology ($7 million) and the proposed refinements for post-retirement benefits ($7.5 million) and derivatives ($14 million), add $28.5 million to PacifiCorp's rate base for Washington operations.[352]

Staff supports the two adjustments, and agrees with PacifiCorp that regulatory assets and liabilities for post-retirement benefits should be included in the current assets and current liabilities columns of the ISWC calculation, rather than in the investment columns. Staff says it supports the Company's proposal "because it achieves a proper balance of ratepayer interests and allows investors to earn a return on the net unamortized funds they contributed to employee post-retirement benefits."[353]

237 Staff also agrees that derivatives, on a net basis, should be included in the investments column of the ISWC calculation as non-operating or "non-utility" investment, rather than the current assets and current liabilities columns.[354] Staff says this refinement is consistent with the Commission's accounting order in Docket UE-010453, that authorized the establishment of a regulatory asset or liability for the effects of certain derivative and hedging accounting rules. The Company may find itself in a net gain or net loss position depending on the timing of the valuations presented on the balance sheet. Therefore, Staff argues, the refinement proposed for derivatives protects ratepayers from the unintended consequence of potential losses by allocating these items to "non-utility" investments. In this way, the Commission is assured that

[350] *Id.* at 2:10-12.

[351] *Id.* at 2:13-15; Exhibit No. DKS-2.

[352] Staff Initial Brief ¶ 182 (citing Zawislak, Exh. Nos. TWZ-1T at 8:3-4, TWZ-2 and TWZ-3).

[353] *Id.* ¶ 183 (citing Zawislak, Exh. No. TWZ-1T at 3:20-22).

[354] Staff Initial Brief ¶ 184 (citing Stuver, Exh. No. DKS-1T at 6:4-7:17 and Exh. No. TWZ-3 at 1:30, 2:63-65, 3:126, and 3:143-146).

a double-recovery (or, conversely, a double-penalty, as in this case) will be avoided.[355]

238 Public Counsel opposes PacifiCorp's proposed changes to the calculation of working capital. Mr. Coppola testifies that the net impact of the proposed changes is to increase the amount of working capital from approximately $7 million to $28.5 million, a four-fold increase. The revenue requirement related to working capital similarly increases from nearly $900,000 to $3,591,618.[356]

239 Public Counsel argues that "[t]he adjustments to the ISWC calculations are a marked departure from the methodology approved by the Commission in PacifiCorp's 2010 rate case."[357] Mr. Coppola testifies that he does "not see a compelling argument to change that methodology."[358] Therefore, he recommends that the proposed change be rejected.

240 *Commission Determination:* We are not persuaded by Public Counsel's opposition to PacifiCorp's ISWC adjustment. It does not address, or even acknowledge, Mr. Zawislak's testimony that the increase the Company proposes is not a departure from what the Commission approved in the 2010 general rate case.[359] As Mr. Zawislak testifies, PacifiCorp's ISWC adjustment is a refinement to the methodology that corrects the calculation of ISWC with respect to pensions and other post-retirement benefit liabilities including the associated regulatory assets and derivative assets and liabilities. We determine that PacifiCorp's adjustment to working capital relying on the ISWC approach is supported by the record and should be allowed.

G. Summary of Revenue Requirement Determinations

241 Appendix A to this Order shows the Commission's determinations of the contested adjustments discussed above. Appendix B shows the uncontested adjustments, which

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[355] Zawislak, Exh. No. TWZ-1T at 9:11-18.

[356] Coppola, Exh. No. SC-1CT at 28:3-7.

[357] *WUTC v. PacifiCorp, d/b/a Pacific Power & Light Co.,* Docket UE-100749, Order 06, ¶¶ 290-296 (March 25, 2011).**Error! Bookmark not defined.**

[358] Coppola, Exh. No. SC-1CT at 8:8-15.

[359] *See* Public Counsel Initial Brief ¶¶ 82-90. *See also* Public Counsel Reply Brief ¶¶ 16-19.

we approve without the need for further discussion. Based in part on these adjustments, we portray in Table 9 the revenue requirement that we approve for recovery in rates.

TABLE 8 **Revenue Requirement**	
Rate Base Rate of Return	$811,235,561 7.36%
NOI Requirement Pro Forma NOI	$59,706,937 $49,361,458
Operating Income Deficiency Conversion Factor	$10,345,479 .61940
Gross Revenue Requirement Increase	$16,702,420

H. Settlement: Cost of Service, Rate Spread, and Rate Design

242 On August 21, 2013, the Parties filed a Partial Settlement on Cost of Service, Rate Spread and Rate Design, along with supporting testimony. The settlement proposes to apply PacifiCorp's class cost-of-service study for purposes of establishing rate spread and rate design in this proceeding.[360]

243 No one expressly contested the Company's cost-of-service study. The settlement, however, expressly reserves each Party's ability to litigate cost-of-service principles, applications and consequences in any future PacifiCorp rate proceeding. In addition, the Company agreed with Staff's recommendation that PacifiCorp should conduct a new cost-of-service study and address alternative rate designs that include impacts on

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[360] *See* Paice, Exh. No. CCP-5. The cost-of-service study measures whether the revenue provided by customers recovers the cost to serve that class of customers. This is accomplished by apportioning the Washington per books revenue, expenses, and rate base associated with providing service to defined groups of customers.

low-income customers. PacifiCorp will also conduct a new survey of residential consumption no later than July 31, 2014, for the Company's Washington service area. This information will help the parties in PacifiCorp's next general rate case to formulate alternative rate spread and rate design proposals by providing data relevant to the Company's current Washington operations.

244 Rate spread allocates the Company's revenue requirements among customer classes, informed by the cost to serve each class as shown in the cost-of-service study. The goal of this exercise is to promote "parity," assigning the Company's costs for recovery from the customers who cause them to be incurred. PacifiCorp's cost-of-service study shows that most rate schedules are already within 10 percent of parity. The exception is street lighting, which is significantly above parity. Considering this, the parties agree that any revenue requirement increase ordered at the conclusion of this case should be applied as a uniform percentage increase for all rate schedules, with the exception of the street lighting rate schedules, which should receive no increase.[361]

245 Rate design is the development of the specific rates or charges in the tariff – such as monthly basic charges, demand-related charges, and energy-related charges – that recover the revenue requirement from customers. Specific charges are developed based on total allocated revenue and test period billing determinants (*i.e.*, number of customers, billed kilowatts, and billed kilowatt-hours) for each rate schedule. In their settlement, the parties agree to an equal percentage increase to all demand and energy rate components within each rate schedule.

246 The parties also agree that the monthly Basic Charge for residential service under Schedules 16 and 17 should increase from $6.00 to $7.75 to reflect better the customer-related costs to serve residential customers. This provides for recovery of additional fixed costs via the basic charge, but is significantly less than the increase to $10.00 requested by the Company, thus acknowledging the regulatory principle of gradualism as well as the analyses of Commission Staff and Public Counsel.

247 PacifiCorp's rate design has an inverted block structure for residential service whereby customers using more than a certain second-tier threshold pay more per

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[361] Joint Settlement Testimony, Exh. No. S-2 at 4:7-14.

kilowatt hour than what they pay for use within the first tier. Staff agreed to defer consideration of its proposed residential rate design changes that would increase the upper end of the first consumption tier from 600 kWh to 800 kWh and would incorporate a third residential tier. The Energy Project believes that this proposal, as originally proposed, would have had significantly adverse and disproportionate impacts on low-income customers' monthly bills. This conclusion is based on the premise that low-income customers are relatively higher users, especially in winter months when they often rely on an electric heat source. This results from a number of factors, including the financial inability of the poor to replace high-cost electric heating with a lower cost heat source such as natural gas. Furthermore, low-income customers typically lack the means to install energy-saving measures in their residences, and low-income housing stock is often extremely energy-inefficient.

248 If low-income customers are relatively higher users, then the increase of the existing first tier consumption upper end from 600 kWh to 800 kWh, and the inclusion of a third tier, could have a significantly disproportionate impact on the monthly bills of low-income customers as the recovery of the overall residential class revenue requirement would be shifted to higher users. Without more statistical analysis and some attempt to identify low-income customers who do not participate low-income assistance programs, it is difficult to know whether creating a third tier or raising rates more in the higher tiers unduly burdens those who have the least ability to pay.

249 Thus, the agreement to defer residential rate design changes as proposed by Staff until the Company's next rate case and pending the collection and analysis of additional information that will reveal the impact of such design changes on the poor is a reasonable settlement provision. This additional time will give all interested parties, including the Energy Project, the opportunity to conduct their own analyses using information that the Energy Project and the Company have recently collected and analyzed, as well as additional relevant information.

250 *Commission Determination:* PacifiCorp's cost should be spread, and its rates should be designed, so that they reflect the costs of providing service, are adequate to recover the Company's revenue requirement, are reasonably stable and fair, send proper price signals, and are relatively simple. The parties' settlement achieves these goals for the most part. In addition, the settlement provides for the development of information that will better enable the Commission to evaluate and implement proposed changes in rate design intended to promote conservation, as initially proposed by Staff in this case, while protecting the most vulnerable of PacifiCorp's customers. Adding a third tier to the Company's inverted block rate structure for residential service is an idea worth revisiting in PacifiCorp's next general rate case when the Commission will be better informed concerning the possible impacts of such a change on low-income customers.[362]

251 We determine that the Commission should approve and adopt the parties' settlement agreement as a reasonable resolution of rate spread and rate design issues. We commend the parties for their plans to develop meaningful information on these subjects that will better inform the Commission in a future case concerning possible changes in rate design that will promote conservation while providing rates that are reasonable and fair to all customers.

I. Low-Income Bill Assistance

252 The customer testimony heard at our public comment hearings in PacifiCorp's service territory,[363] written comments from customers,[364] and testimony and customer comments in earlier cases make us keenly aware of the struggle PacifiCorp's low-income customers face as they balance their needs for goods and services against their financial resources. Facing these issues in PacifiCorp's 2011/2012 general rate case, the Commission approved a settlement that included a five-year plan addressing low-income bill assistance.[365] The plan includes four key elements:[366]

- Beginning in 2012, 10 percent of clients will be certified as eligible for a two-year period with the percent certified rising to 25 percent of clients in 2015. Up to 40 percent of participants will be in some phase of two-year certification by 2016.

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[362] We caution that parties should not abandon what could be sound rate design policy for fear of such potential impacts on low-income customers. There may be other solutions to the problem of such adverse impacts, if they are shown to be present.

[363] *See generally* Tr. 33-55 and 59-82.

[364] Exhibit No. B-1 (compilation of written Public Comments).

[365] *See WUTC v. PacifiCorp*, Docket UE-111190, Order 07 ¶¶ 17-18 and 40-44 (March 30, 2012).

[366] *Id.* ¶ 17.

- Agency funding for certifying each client will grow to $65.00, and will increase by $2.50 annually through 2016 to $75.00 per certification.
- Benefits to each participating customer will grow by an average of 10 percent, with additional increases of two times the percentage increase of any future residential general rate increases between 2013 and 2016.
- The Schedule 91 residential surcharge, which funds the Low-Income Bill Assistance or LIBA program, will increase from $0.55 to $0.63 per month, and the Company will file for an increase (absent a general rate case filing) annually, around May 1, to reflect the increased funding requirements described above. The Schedule 91 surcharge increases will be applied on an equal percentage basis to all rate schedules. The parties agree to support the Company's annual May 1 Schedule 91 filings and that such filings will be limited in scope to implementing the Five-Year LIBA Plan.[367]

253 In this case, PacifiCorp proposed specific changes that Mr. Ebert testifies are consistent with the five-year plan and are supported by the Energy Project.[368] The plan, as summarized by Mr. Ebert, includes the following elements:

- As a cost-cutting measure, a percentage of the Company's LIBA recipients are certified every other year, as opposed to annually.
- The program provides assistance to additional recipients.
- The LIBA eligibility certification fee paid to the community action agencies who administer LIBA is incrementally increased.
- Funding for benefits received by LIBA participants is increased on a percentage basis by twice the amount of any rate increase authorized by the Commission for PacifiCorp.[369]

Mr. Ebert testifies that these changes are implemented via a filing by the Company around May 1 of each year during the five-year term of the plan.

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[367] Appendix B of the Settlement sets forth the rates associated with the Five-Year Plan.

[368] Eberdt, Exh. No. CME-1T at 4:15-17.

[369] *Id.* at 3:12-19.

254 In this case, PacifiCorp's proposed LIBA changes include an increase to the LIBA tariff, Schedule 17, that is two times the average residential customer increase proposed in this case the result of which is a proposed 30 percent increase to the average LIBA participant benefit.[370] Ms. Steward testifies that the Company plans to file on or about May 1, 2013, to reflect in the Company's low-income bill assistance surcharge tariff, Schedule 91, increases related to the changes in the number of participants and agency funding. Following a final order in this rate case, the Company proposes to file changes to Schedule 91 as part of the compliance filing to recover the increase in the participant benefits and any other necessary changes.[371]

255 Staff supports the Company's approach to implementing the five-year low-income bill assistance plan.[372] Apparently capturing the effect of the lower revenue requirement PacifiCorp proposes via its rebuttal testimony, Staff states the participant benefit will increase by 26 percent, rather than the 30 percent increase based on the Company's initial filing that reflected a larger increase in revenue requirement. Consistent with the requirements of the five-year plan, reflecting a lower increase that is two times the residential increase determined by the Commission in this order, results in an increased benefit of approximately 11 percent.[373]

256 *Commission Determination:* While the issue of low-income bill assistance is not contested in this proceeding, we call it out for discussion and expressly approve the Company's proposal in this case because the matter is critically important and deserves close attention. As we did in approving the five-year low-income bill assistance program in 2012, we again commend the parties for their proactive endeavors and cooperative behavior in increasing funding to assist those most in

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[370] *Id.* at 4:3-14; *see also* Steward, Exh. No. JRS-1T at 2:11-13 ("As a result of this filing and the five-year plan agreed by parties in the last general rate case, the Low Income Bill Assistance program would see a 36 percent increase in funding, from $1.7 million to $2.3 million.") and 9:1-7 ("As required by the stipulation, the Company has applied an increase to Schedule 17 credits that is two times the average residential customer increase, the result of which is a proposed 30 percent increase to the average LIBA participant benefit.").

[371] Steward, Exh. No. JRS-1T at 9:13-18.

[372] Staff Initial Brief ¶¶ 192-93.

[373] *Id.* ¶ 193.

need. The Commission's observation in this connection in its 2012 order bears repeating:

> While many customers are adversely affected by an increase in their electricity rates, we recognize that the customers eligible for the LIBA program are the most dramatically affected by a rate increase and are the least capable of absorbing any rate increase in their monthly income. Accordingly, changes to the LIBA Program that reduce the administrative burden of annual certification and increase benefits should provide welcome respite to participating customers. Conversely, the increase to the Schedule 91 residential surcharge, eight cents per month, imposes a minimal burden on the customers funding the program.[374]

We encourage continued efforts by the Company, Staff, the Energy Project, and others who recognize the importance of ensuring that low-income customers have access to the vital services PacifiCorp provides, to find innovative means to provide it.

J. Prudence Issues

Swift Fish Collector, Soda Springs Fish Passage, and Prospect In-Stream Flow and Automation Project

257 Ms. Williams, testifying for Staff, addresses the prudence of significant capital improvements to various hydroelectric projects owned by PacifiCorp. These major plant additions to rate base are the Swift Fish Collector, Soda Springs Fish Passage, and Prospect In-Stream Flow and Automation project. Ms. Williams testifies that the Company's acquisitions of the Swift Fish Collector, Soda Springs Fish Passage and Prospect In-Stream Flow and Automation projects are prudent under Commission standards.[375]

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[374] *WUTC v. PacifiCorp*, Docket UE-111190, Order 07 ¶ 42 (March 30, 2012).

[375] Staff witness McGuire presents the specific ratemaking treatment recommended for these projects. Based on Mr. McGuire's recommendation, Ms. Williams does not address the prudence of the Merwin Fish Collector project. Mr. McGuire testifies that the Merwin Fish Collector was not placed into service prior to the filing of this rate case in January 2013, and therefore the expenditures on the project are not known and measurable. Exhibit No. CRM-1T at 3:19-22.

258 Addressing first whether these resources are used and useful, Ms. Williams testifies that the Soda Springs Fish Passage was placed into service in October 2012. Both the Swift Fish Collector and the Prospect In-Stream Flow and Automation project began operation in December 2012.[376] All three capital improvements were required by FERC license. The projects reduce costs to Washington customers by enabling the Company to continue operating the Swift No. 1, North Umpqua Hydroelectric Project and Prospect facilities, instead of acquiring more costly replacement resources.

259 Testimony by Mr. Tallman and Mr. McDougal for the Company shows that PacifiCorp carefully evaluated these projects. In each case, the Company conducted a Relicensing Cost Analysis to compare the economics of relicensing the associated hydroelectric projects (*i.e.,* Lewis River in the case of the Swift Fish Collector and North Umpqua for the other two projects) relative to decommissioning, which would make the projects unnecessary. In each comparison, relicensing was the lower cost option. The projects were required under the new licenses.

260 The Company evaluated each required facility considering multiple design alternatives, which were subject to approval by various government agencies. RFPs in each case resulted in multiple proposals that were evaluated with respect to the technical specifications of the project, construction plan and schedules, and experience of the bidder in constructing similar facilities. The winning proposal was the highest evaluated bidder that provided the lowest cost bid.

261 Staff is satisfied that PacifiCorp provided through the testimonies of Mr. Tallman and Mr. McDougal adequate contemporaneous records of its decision-making processes and supporting analyses with respect to the decisions to construct these facilities. Although the Board of Directors was not the final decision maker in any of these matters, the decisions were appropriately made by a senior executive, consistent with Company policy.

262 *Commission Determination:* No party contests the prudence of the Swift Fish Collector, Soda Springs Fish Passage, or Prospect In-Stream Flow and Automation

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[376] Williams, Exh. No. JMW-1CT at 7:1-10 (citing PacifiCorp Response to Staff Data Request 251, Confidential Attachment).

projects. Staff's thoroughgoing review provides a persuasive record upon which we determine the Company was prudent in developing these projects.

FINDINGS OF FACT

263 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

264 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electrical and gas companies.

265 (2) PacifiCorp is a "public service company" and an "electrical company," as these terms are defined in RCW 80.04.010 and as these terms otherwise are used in Title 80 RCW. PacifiCorp is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

266 (3) PacifiCorp acted prudently in developing the Swift Fish Collector, Soda Springs Fish Passage, or Prospect In-Stream Flow and Automation projects.

267 (4) PacifiCorp demonstrates by substantial competent evidence that its current rates are insufficient to yield reasonable compensation for the electric services it provides in Washington.

268 (5) The record supports a capital structure and costs of capital, which together produce an overall rate of return of 7.36 percent, as set forth in the body of this Order in Table 7.

269 (6) The Commission's resolution of the disputed issues in this proceeding, coupled with its determination that certain uncontested adjustments identified in Appendices A and B to this Order are reasonable, results in our findings that

PacifiCorp's electric revenue deficiency is $16,702,420, as set forth in detail in Table 8, in the body of this Order.

270 (7) PacifiCorp requires relief with respect to the rates it charges for electric service and gas service provided in Washington State so that it can recover its natural gas service and electric service revenue deficiencies.

271 (8) The parties' settlement stipulation addressing cost of service, rate spread, and rate design resolves in the public interest the issues presented. The settlement stipulation is attached to this Order as Appendix C and is incorporated into the body of this Order by this reference.

272 (9) Applying the requirements of the five-year low-income bill assistance program approved in Docket UE-111190 in March 2012 results in an 18 percent increase in funding for PacifiCorp's Low Income Bill Assistance Program, increasing the benefit per participant by 11 percent.

273 (10) The rates, terms, and conditions of service that result from this Order are fair, just, reasonable, and sufficient.

274 (11) The rates, terms, and conditions of service that result from this Order are neither unduly preferential nor discriminatory.

CONCLUSIONS OF LAW

275 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

276 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

277 (2) PacifiCorp failed to show that the rates it proposed by tariff revisions filed on January 11, 2013, which were suspended by prior Commission order, are fair, just or reasonable. These as-filed rates accordingly should be rejected.

278 (3) PacifiCorp carried its burden to prove that its existing rates for electric service and natural gas service provided in Washington State are insufficient to yield reasonable compensation for the service rendered.

279 (4) PacifiCorp requires relief with respect to the rates it charges for electric service and natural gas service provided in Washington State.

280 (5) The Commission must determine the fair, just, reasonable, and sufficient rates to be observed and in force under PacifiCorp's tariffs that govern its rates, terms, and conditions of service for providing natural gas and electricity to customers in Washington State.

281 (6) The costs of PacifiCorp's investments found on the record in this proceeding to have been prudently made and reasonable should be allowed for recovery in rates.

282 (7) PacifiCorp should have the opportunity to earn an overall rate of return of 7.36 percent based on the capital structure and costs of capital set forth in the body of this Order, including a return on equity of 9.5 percent on an equity share of 49.1 percent.

283 (8) PacifiCorp should be authorized and required to make a compliance filing to recover its revenue deficiency of $ $16,702,420 for electrical service provided to its customers in Washington.

284 (9) The Commission should approve and adopt the parties' settlement stipulation addressing cost of service, rate spread, and rate design in full resolution of the issues presented.

285 (10) PacifiCorp should be authorized to increase in funding for the Company's Low Income Bill Assistance Program by 18 percent, which will increase the benefit per participant by 11 percent.

286 (11) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient.

287 (12) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory.

288 (13) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

289 (14) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS THAT:

290 (1) The proposed tariff revisions PacifiCorp filed on January 11, 2013, which were suspended by prior Commission order, are rejected.

291 (2) The Commission approves and adopts the parties' settlement stipulation addressing cost of service, rate spread, and rate design in full resolution of the issues presented. The settlement stipulation, attached to this Order as Appendix C, is adopted by prior reference as if set forth in full in the body of this Order.

292 (3) PacifiCorp is authorized and required to increase funding for the Company's Low Income Bill Assistance Program by 18 percent, which will increase the program benefit per participant by 11 percent.

293 (4) PacifiCorp is authorized and required to file tariff sheets that are necessary and sufficient to effectuate the terms of this Final Order, including determinations of a revenue deficiency of $16,702,420 for electrical service. PacifiCorp must

file the required tariff sheets at least two business days prior to their stated effective date, which shall be no sooner than December 10, 2013.

294 (5) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Final Order.

295 (6) The Commission retains jurisdiction to effectuate the terms of this Final Order.

Dated at Olympia, Washington, and effective December 4, 2013.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chairman

PHILIP B. JONES, Commissioner

JEFFREY D. GOLTZ, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

APPENDIX A

COMMISSION DETERMINATIONS OF CONTESTED ISSUES

	Adjustment	NOI	Rate Base	Revenue Requirement
	Actual Results of Operations	**$33,319,345**	**$770,630,103**	**$37,776,930**
3.6	**Wheeling Revenue Adjustment**	$78,410		($126,590)
3.7	**Ancillary Revenue WA**	$325,561		($525,607)
4.1	**Miscellaneous General Expense**	$11,469		($18,517)
4.2	**General Wage Increase - Restating**	($54,623)		$88,188
4.3	**General Wage Increase - Pro Forma**	($161,084)		$260,065
4.5	**Remove Non-Recurring Entries**	($692,017)		$1,117,238
4.8	**Insurance Expense**	($96,054)		$155,075
4.10	**Membership & Subscriptions**	($1,117)		$1,803
4.12	**Uncollectible Expense**	$109,344		($176,532)
4.13	**Legal Expenses**	($47,018)		$75,909
4.15	**O & M Efficiency**	$678,917		($1,096,087)
5.1	**Net Power Costs-Restating**	$3,183,434		(5,139,545)
5.1.1	**Net Power Costs- Pro forma**	$10,434,026		($16,845,376)
5.2	**James River Royalty Offset**	$630,224		($1,017,476)
5.4	**Colstrip #3 Removal**	$472,099	($8,294,585)	($1,747,789)
6.1	**Hydro Decommissioning**	($40,283)	$77,267	$74,217
6.2/6.2.3	**Depreciation & Amortization Reserve to June 2012 Balance**		($12,957,052)	($1,539,617)
6.3	**Proposed Depreciation Rates-Expense**	($678,010)		$1,094,624
6.3.1	**Proposed Depreciation Rates-Reserve**		($521,546)	($61,973)
6.3.2	**Proposed Depreciation Rates-Tax**	$30,782	$197,931	($26,177)
7.1	**Interest True-up***	($83,187)		$134,303
7.2	**Property Tax Expense**	($112,620)		$181,821
7.3	**Renewable Energy Tax Credit**	$59,001		($95,256)
7.4	**Power Tax ADIT Balance**		($7,524.077)	($894,046)
7.6/7.6.1	**Flow Through Adjustment**	($1,128,435)	($9,120,212)	$738,114
8.1	**Jim Bridger Mine Rate Base Adj.**		$27,864,469	$3,310,986
8.2	**Environmental Remediation**	($175,597)	($146,036)	$266,143
8.3	**Customer Advances for Construction**		($159,520)	($18,955)
8.4	**Major Plant Additions**	($580,513)	$26,015,529	$4,028,505
8.5/8.5.1	**Miscellaneous Rate Base**	$127,171	($21,940,157)	($2,812,345)
8.6	**Powerdale Hydro Removal**	($203,083)	$45,267	$333,249
8.7	**Removal of Colstrip #4 AFUDC**	$17,991	($387,034)	($75,034)
8.8	**Trojan Unrecovered Plant Adjustment**	($6.992)	$1,139,709	$146,714
8.11	**Misc. Asset Sales & Removals**	$341,291	($165,138)	($570,624)
8.12/8.12.6	**Adj. to June 2012 EOP Balance**		$19,855,430	$2,359,315
8.13	**Working Capital**		$28,493,964	$3,385,786
9.1	**Production Factor**	($1,376,333)	$462,296	$2,276,974
	Total Adjusted Results	$49,361,457	$811,235,561	$16,702,420

APPENDIX B

UNCONTESTED ISSUES

	Adjustment	NOI	Rate Base	Revenue Requirement
	Actual Results of Operations			
3.1	**Temperature Normalization**	($434,297)		$701,157
3.2	**Revenue Normalization**	$6,191,105		($9,995,326)
3.3	**Effective Price Change**	$2,814,575		($4,544,035)
3.4	**SO2 Emission Allowance Sales**	$530,211	($1,067,999)	($982,912)
3.5	**Renewable Energy Credit and Renewable Energy Attribute Revenue**	($1,357,737)		$2,221,081
4.4	**Irrigation Load Control Program**	$155,201		($250,567)
4.6	**Pension and Post-Retirement Curtailment and Date Change**	($661,676)	($563,394)	$1,001,308
4.7	**DSM Revenue and Expense Removal**	$3,101,221		($5,006,814)
4.9	**Advertising Expense**	($6,076)		$9,810
4.11	**AMR Savings**	$633		($1,022)
4.14	**Naughton Write-Off**	$138,837		($224,148)
5.3	**BPA Residential Exchange**	($4,796,915)		$7,744,454
7.5	**Washington Low Income Tax Credit**	$8,543		($13,792)
7.7	**Remove Deferred State Tax Expense and Balance**	$1,745,039	$872,520)	(2,713,629)
7.8	**WA Public Utility Tax**	($554,779)		$879,479
7.9	**AFUDC – Equity**	$66,536		($107,421)
8.9	**Customer Service Deposits**	($4,404)	($3,236,612)	($377,479)
8.10	**Regulatory Asset Amortization**	($1,948,686)	$1,664,438	$3,343,863
8.14	**Remove Jim Bridger Impairment Costs**[377]			

[377] PacifiCorp removed these costs in Adjustment 4.5, which is contested on other bases.