

**BEFORE THE WASHINGTON STATE  
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND	)	DOCKET UE-100749
TRANSPORTATION COMMISSION,	)	
	)	
Complainant,	)	ORDER 06
	)	
v.	)	
	)	FINAL ORDER REJECTING
PACIFICORP D/B/A PACIFIC POWER	)	TARIFF SHEETS;
& LIGHT COMPANY,	)	AUTHORIZING INCREASED
	)	RATES; AND REQUIRING
Respondent.	)	COMPLIANCE FILING
	)	
.....	)	

*Synopsis: The Commission rejects revised tariff sheets PacifiCorp filed on May 4, 2010, but authorizes and requires the Company to file tariff sheets stating rates that will recover approximately \$38 million in additional revenue, an increase that the Commission finds to be reasonable. At the same time, the Commission requires the Company to establish a “tracker” mechanism to return to customers through a monthly bill credit revenues the Company receives from the sale of Renewable Energy Credits (RECs). For the first year, the credit mechanism will be sized to return \$4.8 million to customers, thereby offsetting, in part, the impact of the rate increase.*

*The increase results from a balancing of the statutory factors that rates must be fair, just, reasonable, and sufficient. The Company’s increased revenue requirement is being driven by a number of factors, including an increase in net power costs caused by the expiration of certain low-priced natural gas contracts and expiration of Bonneville Power Administration and Mid-Columbia wholesale power contracts; the collection of costs, previously deferred, and return on equity associated with the Chehalis natural gas generation plant approved in the last general rate case, and a substantial amount of investments in transmission and distribution. The Commission is mindful that including these costs in PacifiCorp’s rates requires an unusually large increase, particularly in these economic times, but the Commission also recognizes that the Company must be able to recover its prudently incurred costs to be able to provide the service on which its customers depend.*

*The resulting revenue requirement is based on a capital structure of 49.1 percent equity and 50.6 percent debt, with a 9.8 percent return on equity resulting in an overall rate of return of 7.81 percent. The Commission also makes specific revenue, tax, and rate base adjustments proposed by the parties. The Commission increases, by 21 percent, funding for its Low Income Bill Assistance Program. Finally, the Commission concludes that the rate increase should be spread to all rate schedules, other than street lighting, on an equal percentage basis.*

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**MEMORANDUM**

**I. Background and Procedural History**

- 1 **NATURE OF PROCEEDING:** On May 4, 2010, PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company) filed with the Washington Utilities and Transportation Commission (Commission) revisions to its currently effective Tariff WN U-74 with a stated effective date of June 3, 2010. The purpose of the filing was to increase rates and charges for electric service to customers in the state of Washington.
- 2 PacifiCorp asserted a revenue deficiency of \$56.7 million, which would require a rate increase of 20.88 percent for full recovery. The filing, if allowed to go into effect, would have increased PacifiCorp's rates and charges for electric service to customers in the state of Washington by the indicated amount on the stated effective date of the revised tariff pages, June 3, 2010. The Commission suspended operation of the tariffs by Order 01 entered on May 12, 2010, and set this matter for hearing. Under RCW 80.04.130, the suspension date is April 3, 2011.<sup>1</sup>
- 3 On October 5, 2010, the Commission's regulatory staff (Commission Staff or Staff),<sup>2</sup> the Public Counsel Section of the Office of the Attorney General (Public Counsel),<sup>3</sup> and intervening parties filed their respective responsive testimony. On November 5, 2010, PacifiCorp filed its rebuttal testimony and Staff, Public Counsel, and intervenors filed their respective cross-answering testimony.

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<sup>1</sup> The suspension date is the date on which the revised tariff sheets become effective as a matter of law absent affirmative waiver by the company or entry prior to the suspension date of a Commission final order accepting or rejecting the as-filed tariff pages. If the Commission rejects the as-filed tariff pages, it may leave the company's existing rates unchanged or may order a filing by the company to effect new rates that comply with the Commission's determinations in its final order.

<sup>2</sup> 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 the proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

<sup>3</sup> Public Counsel and the Industrial Customers of Northwest Utilities are collectively referred to as the "Joint Parties."

- 4 The Commission provided members of the public an opportunity to submit written comments throughout the proceeding. In addition, the Commission held a public comment hearing in Yakima, Washington, on October 21, 2010. During the public comment hearing, 29 customers presented testimony in opposition to the proposed rate increase. In addition, the Commission received 297 written comments, 291 of which oppose the proposed rate increase.<sup>4</sup>
- 5 On November 17, 2010, the Commission convened a second prehearing conference to address issues raised by the manner in which the parties filed testimony and exhibits. During an off-record explanatory session, the Commission made available its policy advisors to specifically describe the filing deficiencies and to respond to questions. At the conclusion of the prehearing conference, the Commission required the parties to submit revised and or supplemental testimony and exhibits addressing the deficiencies identified during the second prehearing conference.
- 6 On November 23, 2010, PacifiCorp filed supplemental and revised testimony. On December 6, 2010, Staff, Public Counsel, and ICNU filed revised and supplemental responsive testimony. On December 10, 2010, PacifiCorp filed revised and supplemental rebuttal testimony and Staff filed supplemental cross-answering testimony.<sup>5</sup>
- 7 On January 25, 26, and 27, 2011, the Commission conducted evidentiary hearings in Olympia, Washington. Chairman Jeffrey D. Goltz, Commissioner Patrick J. Oshie, and Commissioner Philip B. Jones were assisted at the bench by presiding Administrative Law Judge Patricia Clark. During the course of the hearing, 25 witnesses presented prefiled testimony and exhibits totaling more than 3,200 pages.<sup>6</sup>

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<sup>4</sup> The public comment exhibit, Exh. No. 8, was filed on February 3, 2011, after the evidentiary hearing in this matter had concluded. Accordingly, the Commission admits Exh. No. 8 with this reference. Any party opposing its admission should file an objection within three business days of the date of this Order.

<sup>5</sup> The parties filed numerous corrections and revisions to their testimony which will not be independently referenced in this Order. A complete listing of all revisions and corrections is available in the docket pages of this case.

<sup>6</sup> Bench Request No. 3 was issued, and its response filed, after the hearing concluded in this matter. The Commission will admit the Response to Bench Request No. 3 as Exh. No. 15C absent objection received within three days of the date of this Order.

PacifiCorp presented the testimony of Richard P. Reiten, Dr. Samuel Hadaway, Bruce N. Williams, Gregory N. Duvall, R. Bryce Dalley, Ryan Fuller, Erich D. Wilson, C. Craig Paice, William R. Griffith, Douglas Stuver, and Rebecca Eberle. Staff presented the testimony of Michael Foisy, Thomas Schooley, Kenneth Elgin, Alan Buckley, Kathryn Breda, and Vanda Novak. The Joint Parties sponsored the testimony of Greg Meyer. ICNU presented testimony from Randall Falkenberg, Michael Gorman, Donald Schoenbeck, Michael Early, and Nicholas Nachbar. Walmart offered the testimony of Steve W. Chriss. The Energy Project presented the testimony of Charles Eberdt. The transcript of this proceeding is more than 800 pages.

8 All parties filed initial post-hearing briefs on February 11, 2011. All parties filed reply briefs on February 18, 2011. The Commission resolves the disputed issues and determines the Company's revenue requirement in this Order, as summarized in Appendix A.

9 **APPEARANCES:** Katherine A. McDowell, Amie Jamieson, and Jordan White, McDowell, Rackner & Gibson PC, Portland, Oregon represent PacifiCorp. Melinda J. Davison and Irion Sanger, Davison Van Cleve, P.C., Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Brad M. Purdy, attorney, Boise, Idaho, represents The Energy Project. Arthur A. Butler, Ater Wynne LLP, Seattle, Washington, represents Wal-Mart, Inc., and Sam's West, Inc. (Walmart). Sarah Shifley, Assistant Attorney General, and Simon ffitch, Senior Assistant Attorney General, Seattle, Washington, represent the Public Counsel Section of the Office of the Attorney General (Public Counsel). Donald T. Trotter, Senior Counsel, Olympia, Washington, represents the Commission Staff.

10 **SUMMARY OF COMMISSION DETERMINATIONS:** We find, on the basis of the evidence presented, that PacifiCorp requires rate relief for its electric service operations in the state of Washington, but we also find that the Company's as-filed rates do not meet the statutory fair, just, reasonable and sufficient standard for approval. We conclude that PacifiCorp should be authorized and required to file revised tariff sheets effecting rates on the basis of an increase in revenue requirement

of approximately \$38 million based on our resolution of the contested issues. The following table summarizes in concise fashion our determinations in this case.<sup>7</sup>

**TABLE 1**  
**Summary of Commission Determinations**

<b>REVENUE ADJUSTMENTS</b>	<b>Commission Determination</b>
Should the Commission establish a tracker mechanism to ensure that ratepayers receive the benefit of Renewable Energy Credits (REC) in rates?	YES
Should the Commission authorize a five-year amortization period for current and past SO <sub>2</sub> emission allowance revenues in its cost of service?	YES
Should the Commission approve PacifiCorp's residential sales temperature normalization adjustment?	YES
Should the Commission approve PacifiCorp's commercial sales temperature normalization adjustment?	NO
Should the Commission approve PacifiCorp's restating and <i>pro forma</i> wage increases?	YES
Should the Commission approve PacifiCorp's affiliate management fee of \$7.1 million?	YES
Should the Commission approve the Joint Parties' proposed modification to the Company's annual incentive compensation plan?	NO
Should the Commission approve the Joint Parties' proposed modification to legal expenses?	NO
<b>NET POWER COST ADJUSTMENTS</b>	<b>Commission Determination</b>
Should the Commission approve an adjustment to include arbitrage sales to reduce net power costs?	YES
Should the Commission approve the parties' partial settlement regarding the Seattle City Light Stateline Contract, wind integration costs, and Chehalis reserves?	YES
Should the Commission approve an intra-hour wind integration adjustment?	YES
Should the Commission approve an adjustment to the Sacramento Municipal Utility District contract?	YES
Should the Commission approve an adjustment related to the Colstrip Unit 4 forced outage rate?	YES
Should the Commission approve an adjustment related to the Direct Current Intertie contract?	YES
Should the Commission approve an adjustment to the Idaho Point-To-Point Transmission Contract?	YES
Should the Commission approve ICNU's logic screen modification?	YES
Should the Commission approve ICNU's eastern market sale adjustments?	NO
Should the Commission approve ICNU's non-firm transmission adjustment?	NO
Should the Commission approve ICNU's modified planned outage schedule for the Hermiston generating plant?	NO
Should the Commission approve ICNU's Jim Bridger Fuel adjustment?	NO
Should the Commission approve ICNU's minimum loading and deration adjustment?	YES

<sup>7</sup> The actual revenue requirement number cannot be stated with specificity until after the Company re-runs its power cost model with the adjustments approved in this Order. However, in Appendix A attached to this Order, we estimate the revenue requirement to be \$37,999,194.



<b>TAX ADJUSTMENTS</b>		<b>Commission Determination</b>																									
Should the Commission Staff's modification to the Company's proposed "repairs deduction" method of accounting?		YES																									
Should the Commission approve PacifiCorp's current year deferred tax normalization adjustment?		NO																									
Should the Commission approve the Company's request to establish an interest reserve account?		NO																									
<b>RATE BASE ADJUSTMENTS</b>		<b>Commission Determination</b>																									
Should the Commission accept Staff's Jim Bridger Mine Operations & Maintenance adjustment?		YES																									
Should the Commission accept Staff's "current assets" adjustment?		YES																									
Should the Commission accept Staff's calculation of working capital?		YES																									
<b>RATE OF RETURN</b>																											
<table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th style="width: 30%;">Component</th> <th style="width: 20%;">Share (%)</th> <th style="width: 20%;">Cost (%)</th> <th style="width: 30%;">Weighted Cost</th> </tr> </thead> <tbody> <tr> <td>Equity</td> <td style="text-align: center;">49.1</td> <td style="text-align: center;">9.8</td> <td style="text-align: center;">4.81</td> </tr> <tr> <td>Long-term debt</td> <td style="text-align: center;">50.60</td> <td style="text-align: center;">5.89</td> <td style="text-align: center;">2.98</td> </tr> <tr> <td>Short-term debt</td> <td style="text-align: center;">0</td> <td style="text-align: center;">0</td> <td></td> </tr> <tr> <td>Preferred</td> <td style="text-align: center;">.30</td> <td style="text-align: center;">5.41</td> <td style="text-align: center;">.02</td> </tr> <tr> <td><b>Overall Rate of Return</b></td> <td></td> <td></td> <td style="text-align: center;"><b>7.81</b></td> </tr> </tbody> </table>				Component	Share (%)	Cost (%)	Weighted Cost	Equity	49.1	9.8	4.81	Long-term debt	50.60	5.89	2.98	Short-term debt	0	0		Preferred	.30	5.41	.02	<b>Overall Rate of Return</b>			<b>7.81</b>
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Equity	49.1	9.8	4.81																								
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<b>Overall Rate of Return</b>			<b>7.81</b>																								
		<b>Commission Determination</b>																									
<b>LOW INCOME PROGRAM</b>																											
Should the Commission approve a 21 percent increase in the Schedule 91 surcharge to fund PacifiCorp's Low Income Bill Assistance program		YES																									
<b>MID-AMERICAN ENERGY HOLDING COMPANY (MEHC) COMMITMENT</b>																											
Should the Commission find PacifiCorp has satisfied Commitment 37 made at the time of its acquisition by MEHC?		YES																									
<b>COST-OF-SERVICE STUDY</b>																											
Should the Commission accept PacifiCorp's modifications to its cost-of-service study?		YES																									
Should the Commission accept ICNU's adjustment to peak demand?		NO																									
<b>RATE SPREAD</b>																											
Should the Commission approve Staff's modification to PacifiCorp's rate spread?		NO																									
<b>RATE DESIGN</b>		<b>Commission Determination</b>																									
Should the Commission increase the residential basic charge of \$6.00 and, if so, to what level?		NO																									
Should the Commission approve the Company's original rate design?		YES																									

## II. Discussion and Decisions

### A. Introduction

11 In the context of a general rate case, our statutory duty is to balance the needs of the public to have safe and reliable electric service at reasonable rates with the financial ability of the utility to prospectively provide such service. The Commission must

establish rates that are “fair, just, reasonable and sufficient.”<sup>8</sup> The rates must be fair to both customers and the utility; just in that the rates are based solely on the record in this case following the principles of due process of law; reasonable in light of the range of potential outcomes presented in the record; and sufficient to meet the financial needs of the utility to cover its expenses and attract capital on reasonable terms.<sup>9</sup>

12 In this case, the parties advocate significantly different revenue requirements for PacifiCorp. We must determine, on the basis of the record, the Company’s prudently-incurred expenses and allow recovery of those expenses prospectively in rates. In addition, we must determine what items should be included in the Company’s “rate base” and allow for a reasonable return on that rate base.<sup>10</sup> This process allows the Company to recover its investment in the plant necessary to provide electric service, repay its lenders, and provide it with the opportunity to earn a reasonable return or profit. The sum total of the Company’s expenses plus return on rate base is the revenue requirement, or the amount we allow the Company to recover in rates. The Washington Supreme Court explained this ratemaking 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 requirement;

O is its operating expenses;

B is its rate base; and

r is the rate of return allowed on rate base.

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<sup>8</sup> RCW 80.28.010(1); 80.28.020.

<sup>9</sup> *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944) and *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

<sup>10</sup> The rate base includes both the Company’s investment in infrastructure plus “working capital” supplied by investors to fund the Company’s daily operations.

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.<sup>11</sup>

We use this general formula to calculate PacifiCorp's revenue requirement in this case.

- 13 We base our analysis on an examination of data from the calendar year that preceded the Company's initial filing, referred to as an "historical test year," because cost, revenue, plant data, and other pertinent information are known and measurable.<sup>12</sup> However, we recognize that actual test year data may not be representative of the Company's operations for the period that rates will be in effect. Thus, subject to important conditions, the Company's rate filing may include restating and *pro forma* adjustments.<sup>13</sup> We further modify the historical test year approach to recognize that, for certain expenses such as the costs the Company incurs to generate electricity, or "net power costs," a forward looking approach is more appropriate. For example, we commence our consideration of the Company's net power costs using its Generation and Regulation Initiative Decision tools model, known as GRID, which forecasts power costs for the rate year. These future costs are then matched to test year loads through the production property adjustment.
- 14 The parties propose both restating and *pro forma* adjustments. For restating adjustments, we consider whether certain expenses recorded during the test year are extraordinary and should be adjusted to more normal levels for the expenses in question. For *pro forma* adjustments, we consider whether the proposed change is "known and measurable" and, if so, whether it is offset by other factors, a concept

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<sup>11</sup> *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Docket Nos. UE-090704/UG-090705, Order 11 at ¶ 19 (April 2, 2010).

<sup>12</sup> For a more complete discussion of general ratemaking theory in this jurisdiction, see *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Docket Nos. UE090704/UG-090705, Order 11 (April 2, 2010).

<sup>13</sup> WAC 480-07-510(3)(e)(ii) - (iii) provide definitions of restating actual adjustments and *pro forma* adjustments.

known as the “matching principle.” To be “known,” the event that causes a change to test year levels must have occurred either within or soon after, the test year and must be in place during the period rates will likely be in effect. To be “measurable,” the amount of the change must be calculable, not projected or estimated.<sup>14</sup>

- 15 The “matching principle” requires that all factors affecting a *pro forma* change be considered in determining a *pro forma* level of expense. Offsetting factors may “cancel out” or mitigate the impact of a known and measurable change. There are two aspects to offsetting factors: (1) whether the increase in expense directly produces offsetting benefits; and (2) whether the *pro forma* adjustment is reasonably close to the test year so that offsetting factors can be determined with reasonable accuracy.<sup>15</sup>
- 16 Once we have determined the total revenues PacifiCorp needs to recover its costs and to have the opportunity to earn its authorized rate of return, we must establish the rates the Company may charge its customers. We use a cost of service study to determine the costs caused by each class of customer, including residential, commercial, and industrial customers. We then determine the rate spread, i.e., the portion of the total authorized revenue that the rates charged to each customer class is responsible for generating. Finally, we establish the rate design, which structures the rates the Company charges each customer class to generate those revenues.
- 17 We now turn to the issues in this case. PacifiCorp proposed a rather dramatic increase in rates, over 20 percent. While, after receiving responsive testimony by Staff and other parties, the Company reduced its request to 17.85 percent, that is still an exceptionally high request. Understandably, ratepayers who testified at the public comment hearing in this proceeding<sup>16</sup> and who submitted written comments<sup>17</sup>

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<sup>14</sup> Again, there are exceptions for certain projected costs like net power costs.

<sup>15</sup> *All* adjustments proposed by any party should be supported by a written description of each adjustment describing the reason, theory, and calculation of the adjustment. In this proceeding, there were a number of instances of unsupported conclusions and mere arithmetic calculations that posed some difficulties in evaluating the record. This could be explained in part by the fact that since 2006, all requests for rate relief have been resolved by settlement. Though we do not wish to discourage settlements, all parties should understand that the Commission needs to be able to understand fully, and modify where appropriate, the adjustments proposed by the parties.

<sup>16</sup> Transcript, Volume II, pp. 24 – 90.

<sup>17</sup> Exh. No. 8, Public Comments.

expressed outrage at the magnitude of the increase, particularly given the present state of the economy<sup>18</sup> and the fact that this is PacifiCorp's fifth request for a rate increase in six years.<sup>19</sup> Our responsibility is to take these concerns into account in setting rates that are "fair, just, and reasonable." However, part of our statutory mission is also to ensure that rates are "sufficient." Accordingly, though we wish it were not necessary to do so, we do approve a rate increase, and one that by its percentage alone must be deemed substantial. Much of the Company's increased revenue requirement is being driven by an increase in net power costs caused by (1) the expiration of certain low-priced natural gas contracts and expiration of Bonneville Power Administration and Mid-Columbia wholesale power contracts, (2) the collection of costs, previously deferred, and return on equity associated with the Chehalis natural gas generation plant approved in the last general rate case, and (3) a substantial amount of investments in transmission and distribution.<sup>20</sup> Though, as described above, we reject a number of specific costs associated with these items, many of these costs are justified and must be built into rates.<sup>21</sup>

18 We begin our discussion of the disputed issues with the Company's capital structure and cost of capital because those issues have the greatest impact on the revenue requirement in this case. We then discuss the proposed revenue adjustments commencing again with the adjustment with the greatest impact on the revenue requirement, net power costs. Finally, we discuss the remainder of the proposed adjustments as well as the cost-of-service study, rate spread, and rate design.

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<sup>18</sup> Some of the public reaction was succinct and to the point: "21 percent, you must be joking" and "What in the WORLD is going on?" Others testified to some dramatic personal hardships, reciting the realities of job loss, keeping the thermostat at 58 degrees, and no cost-of-living increases for Social Security recipients. *See* Exh. No. 8.

<sup>19</sup> *See* Public Counsel's Post-Hearing Brief at 1; Initial Post-Hearing Brief of Staff at 1. The Commission approved rate increases of 5.3 percent in 2009, 8.5 percent in 2008, and 6.5 percent in 2007. ICNU's Post-Hearing Brief at 2 – 3.

<sup>20</sup> Reiten, Exh. No. RPR-1T at 3 – 4.

<sup>21</sup> Even ratepayers' advocates, ICNU and Public Counsel, as well as our Commission Staff, recognize that many of these costs should be included in revised and increased rates.

## B. Capital Structure and Rate of Return

19 The Washington Supreme Court has described the task of the Commission in determining the utility's rate of return:

[T he rate of return] is the utility's cost of capital, or the amount of money it must spend to obtain the capital it uses to provide regulated products. Rate of return is the weighted average cost of the utility's various sources of capital (the interest it pays on its debt and the rate of return on its equity) that is necessary to permit it to continue to attract the capital required to provide the regulated product or service—in this case, electricity.<sup>22</sup>

20 More specifically, the Commission must determine the appropriate capital structure for the Company for ratemaking purposes and the cost of each capital structure component, including the cost of equity and debt. The selected capital structure when combined with the individual costs of financing establishes the overall return on investment to be applied to the company's rate base.

### 1. Capital Structure

21 A company's capital structure reflects the way it finances its assets by using equity and debt (and other hybrid securities such as preferred stock). A company's capital structure reflects a blending of equity and debt which ultimately determines a company's exposure to financial risk and the price its ratepayers pay for service. A company may select its own capital structure to meet its needs. However, for ratemaking purposes, the Commission may determine, and frequently has used, a "hypothetical capital structure" on which to set rates.<sup>23</sup> Such a capital structure should be balanced in a way that achieves financial safety while minimizing financial risk so that the company may finance its operations at the least cost.

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<sup>22</sup> *People's Organization for Washington Energy Resources v. The Utilities and Transportation Commission*, 104 Wn. 2d 798, 810 (1986).

<sup>23</sup> *See, e.g., Washington Utilities and Transportation Commission v. Puget Sound Energy*, Docket Nos. UE-090704/UG-090705, Order 11 (April 2, 2010).

22 *Positions of the Parties.* The following table summarizes the parties’ positions on this issue:

		<b>PacifiCorp</b>	<b>Staff</b>	<b>ICNU</b>
Overall Rate of Return		8.34%	7.48%	7.66%
Capital Structure	Equity	52.10%	46.50%	49.10%
	Preferred	0.30%	0.30%	0.30%
	Long-term Debt	47.60%	50.20%	50.60%
	Short-term Debt	0.00%	3.00%	0.00%
Cost Rates	Equity	10.60%	9.50%	9.50%
	Preferred	5.41%	5.41%	5.41%
	Long-term Debt	5.89%	5.89%	5.89%
	Short-term Debt	0.00%	3.0%	0.0%

23 PacifiCorp proposes a capital structure of 52.1 percent common equity, 0.3 percent preferred stock, and 47.6 percent long-term debt.<sup>24</sup> This is based on an average of five-quarters, ending December 31, 2010, which the Company argues smoothes volatility caused by expending capital, issuing and retiring debt, and the retention of earnings and infusion of equity.<sup>25</sup> In effect, the Company proposes its actual capital structure.

24 The Company asserts that the equity in its capital structure reflects the significant capital contributions made by MEHC since it acquired the company<sup>26</sup> It argues that a

<sup>24</sup> Williams, Exh. No. BNW-1T at 3.

<sup>25</sup> *Id.* at 7.

<sup>26</sup> *Id.* at 8, *quoting* a 2006 Commission order, where we acknowledged the “general trend of increasing equity capitalization in the industry”, as further support for the Company’s position.

strong equity position is not only consistent with its current Standard & Poor's (S&P) "A" credit rating, but necessary to maintain its current rating.<sup>27</sup> That "A" credit rating lowers its capital costs and provides the Company more reliable access to capital markets in both stable and volatile periods.<sup>28</sup> However, the Company points out that it had no plans to access these markets before December 31, 2010, so any capital needs would be met through additional equity infusions from MEHC and the retention of earnings. This indicates continued growth in its equity component.<sup>29</sup>

25 The Company does not recognize short-term debt in its capital structure. It did not expect to have any short-term debt during the period ending December 31, 2010,<sup>30</sup> has none outstanding, and there have been periods of time when it does not use short-term debt. Therefore, it believes, that short-term debt is not a permanent source of financing for the Company. PacifiCorp also argues that the use of short-term debt in the capital structure is inappropriate and inequitable because it would be double-counted as financing both the rate base and Construction Work in Progress (CWIP).<sup>31</sup>

26 The Company's proposed capital structure also includes 0.30 percent preferred stock and 47.60 long-term debt. While it did not intend to issue any new long-term debt for the period ending December 31, 2010, the balance of outstanding debt will decrease as a result of maturities and principal amortization.<sup>32</sup> The resulting debt component

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*Washington Utilities and Transportation Commission v. PacifiCorp*, Docket UE-050684, Order 04 at 83 (April 17, 2006).

<sup>27</sup> As additional support, the Company asserts that S&P advised that its stand-alone financial metrics are more consistent with a "BBB" rating.

<sup>28</sup> Williams, Exh. No. BNW-7T at 10.

<sup>29</sup> Williams, Exh. No. BNW-1T at 5. The Company submits that MEHC injected a substantial amount of common equity, in excess of \$990 million, on the balance sheet of PacifiCorp. No party disputes this fact.

<sup>30</sup> *Id.* at 3.

<sup>31</sup> *Id.* Construction Work in Progress or "CWIP" is essentially the amount shown on the utility's balance sheet for capital projects under construction, but not yet complete. Though PacifiCorp does not elaborate on its point, we gather that its argument essentially is that because such CWIP is financed by short-term debt, it is inappropriate also to include such debt in the capital structure.

<sup>32</sup> *Id.* at 8.



would be 47.60 percent of the Company's capital structure. The remainder of the capital structure, 0.30 percent, is preferred stock.

27 In responsive testimony, Staff proposes a hypothetical capital structure of 46.5 percent common equity, 0.3 percent preferred stock, and 3.0 percent short-term debt with a 50.2 percent long-term debt component.<sup>33</sup> It argues a capital structure with 46.5 percent equity would provide a balance of safety and economy and is consistent with the proposition that a company's capital structure should achieve the lowest overall cost of capital.<sup>34</sup> This approach is consistent with Commission decisions that state the general principle that "[t]he appropriate capital structure for ratemaking purposes is one that *balances economy with safety* in view of all of the sources of capital available to the company."<sup>35</sup> Staff contends that PacifiCorp's parent, MEHC, controls the Company's capital structure and has a strong financial incentive to capitalize PacifiCorp with "as much equity as possible."<sup>36</sup> Thus, it implies that the large equity component advocated by PacifiCorp tilts the balance in favor of the Company's shareholders while providing little benefit to its ratepayers.

28 As to the Company's credit metrics, Staff concludes that an equity ratio in the mid-40's would support a "BBB" corporate debt rating and an "A-" secured rating.<sup>37</sup> Staff asserts that such credit ratings are reasonable and points out that most electric utilities have a "BBB" rating.

29 In contrast to the Company and ICNU, Staff imputes three percent short-term debt in its hypothetical capital structure arguing that short-term debt is less expensive than equity and such a result would be consistent with the Commission's ruling in the Company's 2005 general rate case.<sup>38</sup> Its estimate is based on examining the

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<sup>33</sup> Elgin, Exh. No. KLE-1T at 2.

<sup>34</sup> *Id.* at 11.

<sup>35</sup> *Id.* at 12 – 13, citing *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket No. UE-050684, Order 04, (April 17, 2006).

<sup>36</sup> *Id.* at 13.

<sup>37</sup> *Id.* at 15 – 16.

<sup>38</sup> *Id.* at 19.

Company's credit facilities and its cost of issuing commercial paper and considering Avista and Puget Sound Energy's recent cost of short-term debt.<sup>39</sup>

30 The imputed debt represents \$500 million which Staff argues is relatively small compared to net plant of \$15 billion.<sup>40</sup> Staff also contends that PacifiCorp's cash flow requires \$800 million of external funding which it argues should be derived from cheaper short-term borrowings.<sup>41</sup> It points out the Company retains \$1.5 billion in short-term debt credit facilities, from internal sources that could be used to finance its short-term capital needs.<sup>42</sup>

31 In summary, Staff agrees with the Company's allocation of preferred stock in its capital structure. Accordingly, the remaining component of the capital structure, long-term debt, would represent 50.2 percent.

32 ICNU recommends a hypothetical capital structure of 49.1 percent common equity, 0.3 percent preferred stock, and 50.6 percent long-term debt and represents that its hypothetical capital structure is consistent with the capital structure PacifiCorp proposed in prior proceedings.<sup>43</sup> Starting with the Company's actual common equity ending June 30, 2010, ICNU reduces actual equity by \$360 million by removing what it characterizes as the financing associated with: (1) an acquisition adjustment; (2) special deposits (3) short-term investments; and (4) the net amount of affiliated payables and receivable. It asserts that its adjustment reflects the common equity the Company "relied on to invest in utility plant."<sup>44</sup> ICNU points out that while the Company retained all earnings at the subsidiary level and did not pay dividends to its

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<sup>39</sup> *Id.* at 48.

<sup>40</sup> *Id.* at 20.

<sup>41</sup> *Id.*

<sup>42</sup> *Id.* at 19 -20.

<sup>43</sup> Gorman, Exh. No. MPG-1T at 13,15. ICNU uses an average of PacifiCorp's most recent five quarters ending June 30, 2010, to determine its proposed capital structure.

<sup>44</sup> *Id.* at 13.

parent, it did not invest all those earnings in utility plant, and equipment for the benefit of the ratepayers.<sup>45</sup>

33 Having agreed with the Company's 0.3 percent preferred stock component, ICNU proposes that the remainder of the capital structure consist of 50.6 percent long-term debt.<sup>46</sup> As to its recommendation's impact on the Company financial ratings, ICNU calculates key metrics used by S&P with its proposed capital structure and return on equity and concludes that each metric will fall within an acceptable range to support the current A utility bond rating and other related ratings.<sup>47</sup>

34 In rebuttal testimony, the Company contends that Staff "seeks to diminish the Company's credit rating without reflecting any of the costs of doing so."<sup>48</sup> In support, it claims that a credit downgrade would result in an increase in debt costs, could increase fees for borrowing arrangements, and could lead to increased collateral requirements.<sup>49</sup>

35 Regarding Staff's imputation of short-term debt, the Company argues that Staff's proposal implies that short-term debt is used as a source of funding for long-term assets in service and to finance CWIP. The Company contends that this would be reasonable if the balance of short-term debt exceeds CWIP because that might indicate it is using short-term debt to finance long-term assets.<sup>50</sup> However, it contends that is not the case and that imputing short-term debt results in "double counting" because CWIP includes the cost of short term debt.<sup>51</sup>

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<sup>45</sup> *Id.* at 12.

<sup>46</sup> *Id.* at 15.

<sup>47</sup> *Id.* at 38 - 41.

<sup>48</sup> Williams, Exh. No. BNW-7T at 11.

<sup>49</sup> *Id.* at 12.

<sup>50</sup> Williams, Exh. No. BNW-7T at 5 - 6.

<sup>51</sup> *Id.* at 7.

- 36 PacifiCorp also argues that its actual capital structure at the end of the test year includes 0.2 percent of short term debt. However, it argues the Company has no need for short-term debt because it issued a significant amount of new long-term debt in 2009 and received capital contributions from its indirect parent company.<sup>52</sup>
- 37 Rebutting ICNU's proposed equity allocation, PacifiCorp argues that ICNU mistakenly reduces equity related to resources that are actually located in other jurisdictions. The Company argues that financing is not allocated by jurisdiction and that its capital structure is comprised of operations in all states.<sup>53</sup> It also contends that general financial theory does not support ICNU's proposal to offset common equity by netting it against cash (assets).<sup>54</sup>
- 38 In response to ICNU's calculation of credit metrics under its proposed capital structure, the Company contends that ICNU failed to properly reflect rating agency adjustments. For example, it points out that ICNU includes less than half of the imputed debt used by S&P.<sup>55</sup> In addition, the Company argues that ICNU ignores the published expectations of the rating agencies, which leads to a false conclusion about the Company's ability to maintain its current ratings.<sup>56</sup>
- 39 *Commission Decision.* A central tenet of ratemaking is that a Company's capital structure must strike an appropriate balance between safety and economy. In other words, the capital structure must contain sufficient equity to provide financial security, but no more than necessary to keep ratepayer costs at a reasonable level.<sup>57</sup> We conclude that the Company's proposed capital structure contains too much equity, which tips the balance too far in favor of investor interests over ratepayers.

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<sup>52</sup> *Id.* at 4.

<sup>53</sup> *Id.* at 18 - 19.

<sup>54</sup> *Id.* at 19.

<sup>55</sup> *Id.* at 21.

<sup>56</sup> *Id.* at 22.

<sup>57</sup> *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1942).

40 In 2006, the Company's equity ratio was 46 percent.<sup>58</sup> Under the control of MEHC, the equity component of the Company's capital structure expanded to the test year level of 52.1 percent, a remarkable level of growth in just three years. This growth is due to MEHC infusing over \$990 million of equity into the Company, eliminating the payment of dividends to MEHC, and retiring short-term debt.<sup>59</sup> By the Company's own admission, this financial policy will continue for the near future.<sup>60</sup> PacifiCorp expects additional equity infusions from MEHC and intends to retain earnings rather than paying dividends to MEHC, indicating a trend of future growth in its equity component.<sup>61</sup> While we understand MEHC's interest in expanding PacifiCorp's equity ratio and reaping the benefit of greater equity returns, this interest is inconsistent with the ratepayer interest in a capital structure that reflects economy. Accordingly, as recommended by ICNU, we adopt a hypothetical capital structure for ratemaking purposes consisting of 49.1 percent equity, 0.3 percent preferred stock, and 50.60 percent long-term debt.

41 Regarding the equity component, we believe that Staff's proposed 46.5 percent is too low. We recognize that a substantial part of PacifiCorp's increased equity financing is being used for capital expenditures, such as generation, transmission, and distribution investments that provide value to ratepayers. Therefore, we conclude that it is appropriate to increase the equity component above the 46 percent that the Commission approved in the last litigated rate case in 2006. We also recognize that the decision on the appropriate actual capital structure for PacifiCorp will be made by the parent company, MEHC,<sup>62</sup> and by the ultimate owner, Berkshire Hathaway.

42 We conclude that ICNU provides us with the most reasonable approach for calculating the equity component of the Company's capital structure. ICNU in effect determines its proposed equity ratio by ascertaining the equity used to support plant investment. Therefore, it removed \$360 million of equity capital not used to support

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<sup>58</sup> Williams, TR 277.

<sup>59</sup> Gorman, Exh. No. MPG-1T at 12, Williams, Exh. Nos. BNW-1T at 5.

<sup>60</sup> Williams, Exh. No. BNW-1T at 5.

<sup>61</sup> *Id.*

<sup>62</sup> *See* Elgin, Exh. No. KLE-1T at 13.

such plant. This results in an equity component of 49.1 percent and a debt component of 50.60 percent, which we believe strikes an appropriate balance and is likely to maintain the Company's current credit ratings.

43 We are not persuaded, in this case, by Staff's arguments to impute short-term debt in the Company's hypothetical capital structure. As we stated in the 2006 PacifiCorp rate case, "[t]he Commission has traditionally included a component for short-term debt, *based on a company's actual capital structure*"<sup>63</sup> Here, we are not persuaded that that the Company's "actual" capital structure contains such short-term debt. This is not to say that, in an appropriate case, we would not impute short-term debt. As Staff notes, it "is a very low-cost source of funds" and PacifiCorp did include such debt in its capital structure in the past.<sup>64</sup> However, 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. In summary, we adopt a hypothetical capital structure for ratemaking purposes with 49.1 percent common equity, 0.3 percent preferred stock, and 50.60 percent long-term debt.

## 2. Cost of Common Equity

44 Determining the cost of capital requires a series of complex decisions but must conform to specific legal criteria. Rates must be "just, fair, reasonable, and sufficient."<sup>65</sup> In the context of this issue, they must be sufficient to meet the financial needs of the company and attract capital on reasonable terms.<sup>66</sup> "Reasonable terms" are those that allow a return "commensurate with returns on investments in other enterprises having commensurate risks."<sup>67</sup>

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<sup>63</sup> *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket UE-050684, Order 04 at 79 (April 17, 2006) (emphasis added).

<sup>64</sup> Elgin, Exh. No. KLE-1T at 19.

<sup>65</sup> RCW 80.80.010(1); RCW 80.28.020.

<sup>66</sup> *Bluefield Water Works & Improvement Company vs. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

<sup>67</sup> *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944).

- 45 Determining the cost of equity is the most challenging of the various types of financing. Unlike debt, which has a stated cost that is easily determined, the Commission must estimate the cost of equity. There are a number of approaches to estimating the cost of equity.<sup>68</sup> The three approaches used in this case are the Discounted Cash Flow (DCF) method, the risk premium method, and the Capital Asset Pricing Model (CAPM).
- 46 The DCF model is one of the oldest and widely accepted methods to estimate the cost of equity on a forward-looking basis, and that model is based on two fundamental principles. First, the valuation of an asset by investors is based on the future cash flows that the asset will create, *e.g.*, both the annual dividends and the ultimate capital gains through the sale of a utility stock. Second, the valuation is adjusted by the “time value of money,” meaning that a dollar received in the future is worth less than a dollar received today. The discount rate that makes the expected dividends and future sales price of the stock equal to the current market price is the cost of common equity.<sup>69</sup>
- 47 The Risk Premium Method is based on the proposition that common stocks are riskier than fixed income securities and therefore, require a higher expected return. The basic concept of risk premium can be described by the capital market line, which sets forth the relationship between required return and risk in a graph. The basic components of this methodology are a risk-free rate and a premium for anticipated inflation. Several proxies can be used for determining the risk-free rate and include Treasury bonds, Treasury bills, or corporate bonds. The equity risk premium is constant over time.<sup>70</sup>
- 48 The Capital Asset Pricing Model (CAPM) method is a method based on modern portfolio theory that describes the relationship between a security’s investment risk and its market rate of return. The relationship between these two basic parameters (return and risk) identifies the rate of return that rational investors expect a security to

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<sup>68</sup> Charles F. Phillips, Jr., *The Regulation of Public Utilities*, p. 392- 99, (1995).

<sup>69</sup> David C. Parcell, *The Cost of Capital – A Practitioner’s Guide* (1997).

<sup>70</sup> *Id.*

earn, which constitutes a rate that is comparable with the market returns earned by other securities that have comparable risk.<sup>71</sup>

49 *Positions of the Parties.* PacifiCorp proposes a ROE of 10.6 percent and uses the DCF and Risk Premium models. PacifiCorp rejects the use of the CAPM because of the potentially questionable underlying assumptions involved<sup>72</sup> and the conclusion that it would produce “artificially low results,” between 7 percent and 9 percent, under current economic conditions.<sup>73</sup> Therefore, PacifiCorp argues that using the DCF and risk premium analyses provide the most reliable cost of equity estimate.<sup>74</sup> While admitting that the DCF formula does require judgment about future growth rates, PacifiCorp argues that the other component of the DCF formula, dividend yield, is straightforward and “the model’s results are generally consistent with actual capital market behavior.”<sup>75</sup>

50 The Company recognizes its inability to directly estimate its cost of equity because it is a subsidiary of MEHC, is not a publicly-traded company, and does not have a transparent market price for its common stock. Hence, one cannot directly apply one of the critical variables of DCF analysis, common stock price. Therefore, PacifiCorp uses a proxy group of 22 companies and employs three variants of the DCF model.

51 The versions are:

- Constant growth using analysts’ predictions. This method uses analysts’ projections of earnings growth, including *Value Line* and others,<sup>76</sup> and their

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<sup>71</sup> Charles E. Phillips, *The Regulation of Public Utilities*, p. 396 (1995).

<sup>72</sup> Hadaway, Exh. No. SCH-1T at 11.

<sup>73</sup> PacifiCorp’s Initial Post-Hearing Brief ¶ 31; Hadaway, TR 251.

<sup>74</sup> Hadaway, Exh. No. SCH-1T at 17.

<sup>75</sup> *Id.*

<sup>76</sup> *Value Line* (valueline.com) is an independent research firm founded in 1931 that serves the professional investment community as a resource of information on estimates and analysis of earnings growth, dividends, and other financial indicators. Likewise, Zacks investment research (zacks.com) is a full-service advisory firm that publishes earnings and dividends estimates, among others, on a regular basis. Finally, Thomson (Thomson.com) is a long-standing



projected long-term nominal Gross Domestic Product (GDP) growth. The result is an estimated GDP growth rate of 5.57 percent.

- Constant growth using historical data. This method is based on up to 60 years of GDP data to project long-term nominal GDP growth. The result is an estimated GDP growth rate of 6.0 percent.
- Multi-stage growth using *Value Line*. This method uses *Value Line*'s three-to-five year dividend projections in the first stage in this analysis and the projected long-term nominal GDP growth rate in the second stage.<sup>77</sup>

52 All three versions of the DCF model use *Value Line*'s dividend yields computed from *Value Line*'s projections of dividends for the coming year. The Company derives stock prices from the three-month average for the months that correspond to the *Value Line* editions from which the underlying financial data are taken.<sup>78</sup> The Company's DCF models produce a cost of equity range of 10.40 percent to 10.90 percent. The Company's proposed 10.6 percent cost of equity is near the middle of this range.

53 PacifiCorp's risk premium analysis uses current and projected single-A bond interest rates as the base and adds an equity risk premium. The Company computes the equity risk premium by first using the average difference between Moody's average public utility bond yields and authorized electric equity returns from 1980-2009 based on actual commission orders. PacifiCorp then adjusts the resulting "basic risk premium" upward for what the Company characterizes as "the strong inverse relationship between equity risk premiums and interest rates" (*e.g.*, when interest rates are high, risk premiums are low and vice versa).<sup>79</sup> The Company's risk premium analysis results in a ROE range from 10.38 percent to 10.60 percent. PacifiCorp's proposed cost of equity lies at the top of this range.

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investment firm that has provided financial analysis and estimates to financial professionals for decades; in 2008 it merged with Reuters PLC and is a publicly-listed company.

<sup>77</sup> Hadaway, Exh. No. SCH-1T at 34 - 35.

<sup>78</sup> Hadaway, Exh. No. SCH-1T at 35.

<sup>79</sup> *Id.* at 39.

- 54 Staff recommends a cost of equity of 9.50 percent based on its DCF analysis, CAPM analysis, and to a lesser degree, a risk premium analysis. Staff describes the proxy selection process for its DCF analysis as starting with PacifiCorp's 22-company proxy group and eliminating all but six of the companies because of non-utility revenue, excessive risks exposure, or dissimilar markets.<sup>80</sup> Staff argues "a proxy group of twenty-two companies is simply too large and too complex for an investor . . . ."<sup>81</sup> Staff's proxy group excludes all California utilities which it asserts have unreasonably high returns on equity and adds Avista which it asserts is a regional company with similar business characteristics. Therefore, Staff's proxy group consists of seven companies compared to the 22-company proxy group used by the Company and ICNU.<sup>82</sup>
- 55 Staff primarily relies on its DCF analysis which produces an equity range of 9.00 to 9.75 percent. Staff's DCF analysis produces an average dividend yield of 4.63 percent, roughly 20 basis points less than the Company's estimated average yield of 4.82 percent. Although Staff's dividend yield is not materially different from PacifiCorp's, Staff's dividend growth estimate produces results that are more than 100 basis points lower than those produced in PacifiCorp's DCF model. Staff applies Value Line's dividend growth rate, makes what it characterizes as "more reasonable" adjustments to three of its proxy companies, and concludes that a "reasonable expectation for dividend growth is 4.75 percent."<sup>83</sup>
- 56 Staff uses the CAPM method as a "check" of its DCF analysis but argues that its results should be used with considerable caution because each element of the CAPM formula is difficult to measure, there is a presumption that the "past is indicative of the future," and the variables of the model are unrelated to the proxy group.<sup>84</sup> Staff's

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<sup>80</sup> Elgin, Exh. No. KLE-1T at 22.

<sup>81</sup> *Id.*

<sup>82</sup> *Id.* Staff also removed some others, including, for example, Black Hills Corporation, which is primarily a gas utility.

<sup>83</sup> *Id.* at 30 – 31.

<sup>84</sup> *Id.* at 40.

CAPM analysis results in a cost of equity range from 8.30 to 9.70 percent with an average of 9.00 percent.<sup>85</sup>

57 Although Staff does not advocate strongly for its risk premium analysis, it calculates a variant of this method as a second “check” of its DCF analysis.<sup>86</sup> Staff describes the risk premium method as the difference between a long-term debt coupon rate and its estimated equity risk premium arguing that the “magnitude of the [risk premium] spread” shows the reasonableness its recommended return on equity. Staff computes PacifiCorp’s spread at 453 basis points, which it argues represents “excessive compensation” for equity owners.<sup>87</sup> Staff contends that the 300 to 375 basis point risk premium spread reflected in its recommended DCF return of 9.00 to 9.75 percent is adequate compensation in today’s capital markets.<sup>88</sup>

58 Staff concludes that its mid-point recommendation of 9.50 percent based primarily on the DCF analysis, is reasonable and corroborated by its respective calculations using the CAPM and risk premium analyses.<sup>89</sup>

59 ICNU also recommends a 9.50 percent cost of equity. ICNU uses three forms of the DCF analysis: the constant growth model, sustainable growth model, and the multi-stage growth model, along with a risk premium analysis, and the CAPM model.<sup>90</sup> ICNU’s recommendation is the mid-point of the 8.9 percent to 10.3 percent range produced by its three analytic approaches.

60 In its DCF analysis, ICNU uses the same proxy group of 22 companies as that of the Company, noting that, compared to the proxy group, PacifiCorp has “comparable total investment risk,” and “comparable or lower financial risk.” Both PacifiCorp and

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<sup>85</sup> *Id.* at 43.

<sup>86</sup> *Id.* at 44.

<sup>87</sup> *Id.* at 45.

<sup>88</sup> *Id.* at 46.

<sup>89</sup> *Id.* at 47.

<sup>90</sup> Gorman, Exh. No. MPG-1T at 16.

the proxy group have an “Excellent” business risk profile, according to Standard & Poor’s ranking methodology.<sup>91</sup>

- 61 ICNU’s “analyst growth” approach based on the constant-growth DCF model produces a cost of equity range from 10.45 percent (average) to 10.50 percent (median). Accepting the embedded growth rate of 5.67 percent in its analysis, it contends that this growth rate is not sustainable because it exceeds the overall expected economic growth rate of 5.10 percent over the next five years.<sup>92</sup> However, ICNU cautions that this approach leads to a result that is “inflated” because short-term analyst growth rate projections are not reasonable estimates of long-term sustainable growth.<sup>93</sup>
- 62 ICNU’s sustainable-growth DCF approach produces a lower result than the “analyst growth” method; taking the median, the cost of equity range is from 9.14 percent; and taking the mean, it is 9.92 percent (average). ICNU argues that because the proxy group includes an “outlier” with a return on equity of 19.14 percent, it is more reasonable to use the median result.<sup>94</sup> Without the outlier, the mean return would be 9.48 percent.<sup>95</sup>
- 63 ICNU argues that its multi-stage DCF approach reflects a non-constant growth curve for a company over time by using three growth periods: short-term, transition, and long-term.<sup>96</sup> This approach produces an average and median return on equity of 9.87 percent and 9.90 percent, respectively. ICNU combines these results with the other DCF approaches to produce a recommended average DCF return of 9.85 percent, with the caveat that it has “strong concerns about the accuracy of the constant growth DCF.”<sup>97</sup>

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<sup>91</sup> *Id.* at 17.

<sup>92</sup> *Id.* at 21.

<sup>93</sup> *Id.* at 27.

<sup>94</sup> *Id.* at 24.

<sup>95</sup> *Id.*

<sup>96</sup> *Id.* at 25.

<sup>97</sup> *Id.* at 27.

64 ICNU’s risk premium analysis model, based on 30-year bond yields and “A” rated utility bond yields, produces an equity range from 8.98 percent to 9.94 percent with a midpoint of 9.46 percent.<sup>98</sup>

65 ICNU also conducted a CAPM analysis utilizing the basic inputs into such a methodology; market risk-free rate, the Company’s beta, and the market risk premium. It uses a projected 30-year Treasury bond yield of 4.7 percent based on long-term forecasts of economists. Much of the debate around the CAPM analysis centers around the appropriate calculation of market risk premiums and ICNU uses long-term estimates of historical real-market return and market risk premium to develop a range of 5.2 percent to 6.7 percent.<sup>99</sup> ICNU’s final calculation produces a range of 8.28 percent to 9.31 percent with a midpoint of 8.80 percent.<sup>100</sup>

66 In summary, ICNU recommends a “return on equity range” of 9.10 percent to 9.90 percent. This is based on DCF analysis results of 9.85 percent, a Risk Premium result of 9.46 percent, and a CAPM result of 8.80 percent. The low end is based on the average of its CAPM and risk premium return estimates while the high-end is based on DCF analysis. Therefore, ICNU concludes that a 9.50 percent return on equity is reasonable and would support PacifiCorp’s financial integrity.<sup>101</sup>

67 ICNU then conducts various calculations incorporating the above recommendations on capital structure and return on equity on the key financial metrics used by credit rating agencies: debt to Earnings Before Interest Taxes Depreciation and Amortization (EBITDA), funds from operations (FFO) to total debt, and total debt to total capital. It also adjusts for off-balance debt and associated interest expense for

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<sup>98</sup> *Id.* at 32.

<sup>99</sup> *Id.* at 36. This data was taken from Morningstar, *Stocks, Bonds, Bills, and Inflation, 2010 Yearbook*. Morningstar (Morningstar.com) is an independent source of investment advice and analysis that originally was established to provide advice to individuals on mutual funds. It has expanded to provide a full range of independent analysis to institutions and individuals on the risks and returns in equity markets, including historical analysis and forward-looking estimates.

<sup>100</sup> *Id.* at 37.

<sup>101</sup> *Id.* at 37 - 38.

power purchase agreements and operating leases using the S & P report and methodologies. ICNU concludes that its recommendations will produce financial credit metrics that support PacifiCorp's current "A" secured bond rating.<sup>102</sup>

68 ICNU supports its analysis with a critique of the Company's analysis, arguing that PacifiCorp's nominal GDP growth rates in its DCF analysis are not sustainable in the long run; they are excessive and do not reflect current market expectations.<sup>103</sup> ICNU maintains if the Company had used lower GDP projections (4.9 percent instead of 6 percent), PacifiCorp's return would range from 9.9 percent to 10.1 percent.<sup>104</sup> Lastly, ICNU contends that PacifiCorp's DCF results are overstated because the Company's data is stale and does not reflect the market recovery of the last six to nine months. In summary, its critique of the Company's three DCF analyses results in a downward adjustment from an average of 10.7 percent to 10.0 percent return on equity.<sup>105</sup>

69 Continuing its critique, ICNU argues that the Company's risk premium analysis fails because it inappropriately forced an upward adjustment to its derived average equity risk premium resulting in an inverse relationship between interest rates and equity risk premiums. ICNU contends that the inverse relationship promoted by the Company is inappropriate in today's financial markets and inconsistent with academic literature.<sup>106</sup> Further, ICNU contends that the Company's risk premium analysis unreasonably relied on projected interest rates, the accuracy of which is "highly problematic."<sup>107</sup> It concludes this risk premium analysis by adjusting the Company's return downward to a mid-point of 9.55 percent from 10.84 percent contending that more reasonable risk premiums produce a range of 9.06 to 10.3 percent.<sup>108</sup>

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<sup>102</sup> *Id.* at 41.

<sup>103</sup> *Id.* at 44.

<sup>104</sup> *Id.* at 42.

<sup>105</sup> *Id.* at 44 and 46.

<sup>106</sup> *Id.* at 48.

<sup>107</sup> *Id.*

<sup>108</sup> *Id.* at 48, 51.

- 70 In rebuttal, PacifiCorp argues that Staff and ICNU fail to consider financial market turbulence and utility price volatility in their estimates of equity return.<sup>109</sup> It contends that increased market volatility causes investors to require a higher rate of return.<sup>110</sup>
- 71 PacifiCorp also argues that Staff’s and ICNU’s use of the CAPM results in flawed cost of equity recommendations because CAPM inputs, using risk-free proxies such as US Treasury rates, are artificially low” due to the Federal Reserve’s monetary policies and therefore cannot be relied on.”<sup>111</sup> Moreover, it criticizes the inputs used in the risk premium analyses by contending that “[t]o the extent that yields are artificially reduced by the government’s expansive monetary policy, risk premium estimates of ROE will be understated.”<sup>112</sup>
- 72 The Company criticizes Staff’s selection of its proxy group as subjective and too small to be statistically reliable. PacifiCorp argues that Staff did not use a “carefully selected proxy group” because it merely excludes data and replaces it with its own “subjective inputs.”<sup>113</sup>
- 73 The Company contends that Staff’s growth estimates in its DCF analysis are flawed because although Staff starts with *Value Line* growth rates, it then subjectively adjusts its data by eliminating the two highest companies and by substituting reported higher growth numbers with lower estimates.<sup>114</sup> The Company also argues that Staff’s earning retention growth method (b-times-r) is simply not proper and not generally used by economists due to its volatile nature.<sup>115</sup> The Company further contends that

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<sup>109</sup> Hadaway, Exh. No. SCH-8T at 2.

<sup>110</sup> *Id.* at 7.

<sup>111</sup> *Id.* at 11.

<sup>112</sup> *Id.* at 11 – 12.

<sup>113</sup> *Id.* at 13.

<sup>114</sup> *Id.* at 15.

<sup>115</sup> *Id.* at 18.

although Staff uses multiple methods to estimate growth for its DCF computation, the use of the data is dominated by subjective adjustments.<sup>116</sup>

74 The Company suggests that ICNU uses negatively-biased model inputs and that ICNU's use of the CAPM produces results that are currently unreliable.<sup>117</sup> PacifiCorp also contests ICNU's use of short-term GDP growth rate forecasts in its DCF analysis arguing that these rates introduce a downward bias to the results and that this approach is not consistent with what it asserts the DCF model requires; including a long-term growth rate.<sup>118</sup>

75 The Company further argues that ICNU's risk premium analysis does not take into consideration that, when interest rates are low, equity-risk premiums increase and vice-versa. The Company adjusts ICNU's computation with its regression analyses approach and argues that when the inverse correlation between interest rates and equity premiums is included, ICNU's risk premium analysis produces a return approximately 78 basis points higher than ICNU's proposal. In summary, the Company argues that its updated computations to ICNU's analysis, not including a CAPM result, will produce an average return on equity of 10.21 percent.<sup>119</sup>

76 *Commission Decision.* Our determination of the cost of equity requires that we set a rate at which the utility earns a return on investment commensurate with the returns of companies with comparable risks. This task is always complex because we must use our informed judgment to estimate how capital markets will respond in the future to a utility's particular needs for debt and equity capital. The complexity of this task is compounded because the period since the Company's last litigated rate case is one marked by the most severe economic recession since the 1930's. This case presents yet another layer of complexity because PacifiCorp is a subsidiary of MEHC and ultimately receives its capital from Berkshire Hathaway. Therefore, we place somewhat greater weight on the selection of the proxy group and its analysis because of the lack of a transparent price for its equity.

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<sup>116</sup> *Id.* at 15.

<sup>117</sup> *Id.* at 23.

<sup>118</sup> *Id.*

<sup>119</sup> *Id.* at 27.



- 77 Our analysis commences with the composition of a group of companies with business and financial risk comparable to PacifiCorp's. PacifiCorp developed a group of 22 companies for its proxy group. ICNU uses the same group of companies arguing that they are generally comparable in terms of total investment risk, common equity ratio/financial risk, and S&P business risk. Staff creates a new proxy group consisting of six companies from PacifiCorp's proxy group plus Avista, a number that draws significant criticism that it is too small to be statistically reliable.<sup>120</sup> On the other hand, Staff criticizes the Company's larger group as including non-representative utilities.
- 78 There is merit to both arguments. Clearly the 22 member proxy group proposed by the Company and adopted by ICNU contains some companies of dubious comparability,<sup>121</sup> resulting in flaws with the Company's choice of comparable companies. However, we are more concerned with the size of Staff's proxy group, which at seven companies is of questionable statistical reliability. Narrowing a larger and broader proxy group to a smaller one necessarily requires significant subjective analysis regarding its composition and the criteria by which a given company is included or excluded. In general, the smaller the proxy group, the greater possibility for bias to be introduced due to subjective factors. Staff observes that in the 1980's and earlier, the Commission considered proxy groups in telecommunications rate cases that were as small, or smaller, than the one proposed here. However, there are fundamental structural differences between the telecommunications industry at that time and the energy industry now. There were few large telecommunications companies 30 years ago, and they may have been more comparable to each other than energy companies are today. In any event, we have more confidence in the Company's and ICNU's 22 member proxy group than in Staff's seven member proxy group.
- 79 Our focus is on the comparable risk underlying proxy group selection. We do not have to winnow down with precision a proxy group to a level of *identical* risk but instead use our best judgment to consider companies with *similar* characteristics and

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<sup>120</sup> *Id.* at 13.

<sup>121</sup> Black Hills Corporation is primarily a gas utility, and DPL, Inc., produces a return on equity of 19.14 percent.

risks.<sup>122</sup> Therefore, we focus our analysis on the DCF methodologies of PacifiCorp and ICNU using their 22-company proxy group.

80 *DCF Analyses:* We first address the several variants of the DCF formulas used in this case and compare their strengths and infirmities. PacifiCorp uses three versions of the DCF formula resulting in a cost of equity range between 10.40 and 10.90 percent.<sup>123</sup> ICNU also uses three variants of the DCF formula and produces a cost of equity range from 9.14 to 10.50 percent.<sup>124</sup> The primary disagreement between PacifiCorp and ICNU is the estimate of the growth element of the DCF formula. We understand the divergent assumptions that lead to these disagreements and recognize that the parties have legitimate differences of opinion. It is especially difficult to select a projected growth rate for the rate year because the parties disagree about how stable the financial markets have become in light of the unprecedented turmoil that began in the fall of 2008.

81 We conclude that ICNU's analysis is the better one for two primary reasons. First, ICNU more accurately describes the impact of the recent turmoil in the financial markets. The Company argues that utility stock prices and performance are significantly worse than in the previous litigated rate case, especially in the last two to three years, which justifies an upward adjustment. ICNU, however, persuasively argues that financial market conditions have recovered significantly in the past six to nine months and that, over a longer period of time, utility stocks have substantially outperformed other indicators stock performance. We agree with ICNU that financial markets have returned to more normal conditions over the past six to nine months if we consider indicators such as credit spreads, access to debt markets, and valuations of utility stock. Though utility stocks have not recovered as much as non-utility stocks during 2009 and the first half of 2010,<sup>125</sup> evidence is clear that utility stocks are

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<sup>122</sup> See *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679,692 (1923).

<sup>123</sup> Hadaway, Exh. No. SPG-1T at 39.

<sup>124</sup> Gorman, Exh. No. MPG-1T at 19 – 25.

<sup>125</sup> Hadaway, Exh. No. SPG-8T at 6 – 7.

less volatile than non-utility stocks and, in a period of turmoil, are generally considered safer investments.<sup>126</sup>

82 Second, ICNU's criticism of the Company's use of long-term growth rates is valid. Generally speaking, we are hesitant to place too much weight on long-term growth rates, such as nominal GDP rates, because we are uncertain if the growth rates can be sustained over the long-term. It is better to rely on short-term growth rates because we should be able to confirm their reliability in a comparatively brief time. This greater confidence in short-term growth rates leads us to rely more heavily on ICNU's DCF recommendations regarding the various growth estimates.

83 ICNU used its three DCF analyses with the effect of smoothing the impact of their individual results. Because the average considers both long-term and short-term growth rates, the result was an average ROE from the combined DCF methodologies of 9.85 percent.

84 ICNU also adjusted inputs in the Company's GDP growth and Multi-stage growth models, substituting more reasonable growth rates into these models, with the result of revising the Company's range downward from 10.4 to 10.9 percent to 9.9 to 10.1 percent.<sup>127</sup>

85 Summing up the various DCF analyses, the range in the testimony from the low of 9.0 percent (Staff's lower end of its DCF analysis) to 10.9 percent (the Company's upper end) is unrealistic. Adjusting for more reasonable growth rates and giving due consideration to the limits of Staff's small proxy group and the Company's inclusion of some outliers in its proxy group, we find a range of 9.50 to 10.20 a more reasonable range using ICNU's DCF analyses.

86 *Risk Premium Analyses.* PacifiCorp's risk premium analysis produces a range of 10.38 to 10.6 percent based on two methodologies that are somewhat related. The Company first estimates an annual equity risk premium by subtracting the Moody's average bond yield from the authorized returns from state commissions since 1980.

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<sup>126</sup> Gorman, Exh. No. MPG-1T at 6 -8. ICNU's testimony cites the superior performance of the EEI index over the 2000 – 2009 period as 134 percent on a total return basis which substantially outperforms the DJIA return of 14 percent, the S & P 500 index of 9 percent, and the NASDAQ index of negative 44 percent.

<sup>127</sup> *Id.* at 42 – 43.

This yields an equity risk premium of 3.23 percent. However, the Company then adjusts that premium through a regression analysis based on an expectation that, in the future, there will be an inverse relationship between overall interest rates and equity risk premiums. This has the effect of substantially inflating the risk premium to a range of 4.39 to 4.55 percent with a corresponding increase in the return on equity. We are not persuaded that such an adjustment is appropriate, and we are skeptical that such a precise formula based on future estimated projections of inflation can yield such a precise result.

87 ICNU has a more reasonable approach. It develops its risk premium methodology based on two different methods of calculating equity risk premiums. The first attempts to estimate the difference between common equity investments and Treasury bonds while the second calculates the difference between Commission-authorized returns on equity and bond yields for “A” rated companies like PacifiCorp. ICNU posits two calculations of equity risk premiums under this approach and, after adding them to the comparative rate (either a 30-year Treasury bond or an “A” rated utility bond) it develops a range of return on equity estimates from 8.98 to 9.94 percent, with a mid-point of 9.46 percent. Staff’s analysis is consistent with this approach.<sup>128</sup> Accordingly, we find more reasonable a range of ROE based the Risk Premium method to be between 9.5 and 9.8 percent.

88 *CAPM Analyses.* Finally, we turn to the CAPM analyses performed by Staff and ICNU. The inputs and variables for the CAPM analysis are relatively transparent and easy to perform, although parties usually differ over the calculation of the market risk premium. Both Staff and ICNU derive relatively low results employing the CAPM formula in this case. Staff develops a range of 8.30 to 9.70 percent, with a mid-point of 9.0. ICNU develops a return on equity range of 8.28 to 9.31 percent, with a mid-point of 8.80 percent which it then increased to 9.10 percent to use in its summary calculation of return on equity and ultimate recommendation of 9.50 percent.

89 Each party implies that it uses the CAPM as a “check” or reference point against which it can compare the variants of the DCF methodologies as well as the risk premium method. In this particular case, there is no dispute that the CAPM methodology produces results that are at the low range of estimates for return on equity. The Company refused to perform a CAPM analysis allegedly because the

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<sup>128</sup> Elgin, Exh. No. KLE-1T at 44 - 46.

results are not realistic, citing extremely low interest rates. However, low interest rates are a fact of current financial conditions in capital markets and no party suggests that such conditions can be expected to change in the near future, or at least during the projected rate year for this case.

90 Accordingly, while the CAPM results seem abnormally low those results, at a minimum, reflect a reason to be skeptical about the need for higher ROEs for investors in this stagnant economy. At the least, these CAPM results suggest that we should be receptive to arguments to accept ROEs at the lower end of reasonable ranges developed by the other methodologies.

91 We value each of the methodologies used to calculate the cost of equity and do 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. As we observed in our most recent litigated case with Puget Sound Energy,

[T]he Commission has said in more than one order that it appreciates and values a variety of perspectives and analytic results because these serve to better inform the judgment it must exercise than would a single model, or a single expert's opinion. We reiterate that perspective here. We value and rely on multiple methodologies, models, and expert opinions to develop a robust record of evidence to inform our judgment. *It is particularly important to take multiple methods and models into account in the present circumstances of financial turmoil that may affect the input values used in each method.*<sup>129</sup>

Consistent with that statement, we expect the parties to submit evidence and recommendations utilizing all widely-accepted methodologies.<sup>130</sup>

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<sup>129</sup> *Washington Utilities and Transportation Commission v. Puget Sound Energy*, Docket UE-090704/UG-090705, Order 11 (April 2, 2010).

<sup>130</sup> In this case, the Company chose not to present a CAPM analysis because it stated that the results would be "artificially low" or it would not pass the "smell test." By not submitting an analysis, we were denied a tool by which to evaluate the CAPM analyses submitted by other parties. Though those parties submitted their CAPM analyses as a "check" on the other methodologies, as discussed above, they were a useful check that merited more of a review than was provided by the Company.

92 *Case Comparison.* PacifiCorp cites other recent Commission cases, and the positions taken by Staff witnesses in those cases, as evidence that the Staff recommendation is too low.<sup>131</sup> The Company is correct that in Puget Sound Energy's most recently litigated general rate case decided a year ago, we set that company's ROE at 10.1 percent.<sup>132</sup> More recently, we approved a settlement in Avista's most recent rate case that set the ROE at 10.2 percent in November 2010, although we did not have a chance to separately consider the ROE.<sup>133</sup> However, the most recently litigated determination setting the PacifiCorp's cost of capital, albeit in Idaho, lowered the Company's ROE to 9.9 percent in that jurisdiction.<sup>134</sup> Though by no means binding on us, other state commission decisions have set ROEs well below 10.0 percent.<sup>135</sup> Given the relatively low interest rates in the current economic climate, it is fair to assume a general downward trend of ROEs, and certainly a cost of equity lower than the 10.6 percent proposed by PacifiCorp.

93 The return on equity for PacifiCorp, therefore, must be within the reasonableness ranges established in the record. As we have stated, we place substantial weight on ICNU's DCF analysis and its critique of the Company's DCF analysis. We also agree with ICNU's and Staff's criticism of the Company's risk premium analysis. The range of DCF-derived ROEs is 9.55 to 10.21 percent. The range of Risk Premium-derived ROEs is 9.4 to 9.8 percent. The analysis for CAPM gives further weight to a lower adjustment. The highest common ROE in both ranges is 9.8 percent.

94 Based on our review of the extensive record in this case and on our reasoning above, we exercise our informed judgment and conclude that PacifiCorp's cost of equity in

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<sup>131</sup> PacifiCorp Initial Post-Hearing Brief at 9 – 10; *see* Elgin, TR 697 - 701.

<sup>132</sup> *Washington Utilities & Transportation Commission v. Puget Sound Energy*, Dockets UE 090704/UG-090705, Order 11 (April 2, 2010).

<sup>133</sup> *Washington Utilities & Transportation Commission v. Avista Corp.*, Docket UE-100467, Order 07 (November 19, 2010). This cost of equity was the result of a settlement, so we give this case the least weight in our consideration.

<sup>134</sup> Reiten, Exh. No. RPR-11; *In re PacifiCorp*, 2011 WL 770798 (Idaho P.U.C.) (February 8, 2011). In that proceeding, the Company, as here, requested a 10.6 percent ROE.

<sup>135</sup> *See, e.g., Re Niagra Mohawk Power Corporation*, 286 P.U.R. 4<sup>th</sup> 401, 2011 WL 286478 (N.Y.P.S.C., Jan. 24, 2011) (setting ROE at 9.3 percent if the company does not file an increase in rates for one year; otherwise, the ROE would be set at 9.1 percent).

this case should be set at 9.80 percent. We believe that such a conclusion is supported by the evidence and a comparative weighting of all the methodologies submitted.

### 3. Cost of Preferred Stock

95 *Positions of the Parties.* The Company computes its embedded cost of preferred stock by dividing the annual dividend rate by the per-share net proceeds for each series. The embedded cost is multiplied by total par or stated value of each series. Total annualized cost is divided by the total amount of preferred stock outstanding resulting in the weighted average cost or the embedded cost of the company's preferred stock.<sup>136</sup> PacifiCorp uses a December 31, 2010, *pro forma* cost of 5.41 percent.<sup>137</sup> Neither Staff nor ICNU contest PacifiCorp's cost of preferred stock.<sup>138</sup>

96 *Commission Decision.* We accept PacifiCorp's undisputed cost of preferred stock to calculate PacifiCorp's overall rate of return.

### 4. Cost of Long-Term Debt

97 *Positions of the Parties.* The Company computes its embedded cost of long-term debt by calculating the cost by issue based on each series' interest rate and net proceeds at issuance date resulting in bond-yield-to-maturity for each series of debt. For variable rate securities, the Company uses costs at December 31, 2009.<sup>139</sup> Bond yields were then multiplied by the outstanding principal amount resulting in the annualized cost for each issue. The total annual costs divided by total principal outstanding produces the weighted average cost for all long-term debt issues.<sup>140</sup> The Company's embedded cost of long-term debt, as of December 31, 2010, was computed at 5.89 percent.<sup>141</sup> The Company asserts that its cost of long-term debt is reasonable and compares

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<sup>136</sup> Williams, Exh. No. BNW-1T at 15.

<sup>137</sup> *Id.* at 16.

<sup>138</sup> Elgin, Exh. No. KLE-1T at 3, 7; Gorman, Exh. No. MPG-3 at 1.

<sup>139</sup> Williams, Exh. No. BNW-1T at 14.

<sup>140</sup> *Id.* at 15.

<sup>141</sup> *Id.*

favorably with other utilities under the Commission’s jurisdiction.<sup>142</sup> In response to Staff’s and ICNU’s testimony on capital structure and cost of capital, the Company contends that its cost of debt would increase substantially if its credit rating were to decrease to a “BBB.”

98 Staff and ICNU do not contest PacifiCorp’s calculation of the cost of long-term debt.<sup>143</sup>

99 *Commission Decision.* We adopt the undisputed cost of long-term debt as 5.89 percent.

100 The following table is a summary of our decisions on an appropriate capital structure for the Company and the cost for each component:

**Commission Decision**

	Share %	Cost %	Weighted Cost %
Equity	49.10	9.80	4.81
Long-term Debt	50.60	5.89	2.98
Short-term Debt	0.00	0.00	0.00
Preferred	0.30	5.41	0.02
<b>OVERALL ROR</b>			7.81

**5. General Commitment 37**

101 By Order 07 entered February 22, 2006, in Docket UE-051090,<sup>144</sup> the Commission accepted the Company’s commitment for five years, following the acquisition of

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<sup>142</sup> PacifiCorp’s Initial Post-Hearing Brief at 9 -10.

<sup>143</sup> Elgin, Exh. No. KLE-1T at 47; Gorman, Exh. No. MPG-3 at 1.

<sup>144</sup> *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.*



PacifiCorp by MEHC, to spread incremental long-term debt issuances 10 basis points below the Company's similarly-rated peers.<sup>145</sup> The Company states that the five-year commitment ended on March 21, 2011 (before the end of the suspension period in this docket).<sup>146</sup> The Company requests that the Commission recognize its compliance with General Commitment 37 and include a finding in the final order in this case that the requirements of the Commitment been fulfilled and the Commitment is complete.<sup>147</sup>

102 *Commission Decision.* No party opposed PacifiCorp's request. We find that PacifiCorp fulfilled the requirements of Commitment 37 and this Commitment is complete.

### C. Revenue Adjustments

#### 1. Net Power Costs

##### a. Introduction.

103 Net power costs (NPC) represent the costs the Company incurs to generate and transmit electricity to its customers. Many of the issues in the determination of NPC involve evaluation of the merits of the Company's Generation and Regulation Initiatives Decision tools model, known as "GRID."<sup>148</sup> The Company describes in general terms how the model works:

The [GRID] model is the Company's hourly production dispatch model, which is used to calculate net power costs. It is a server-based application that uses the following high-level technical architecture to calculate net power costs:

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<sup>145</sup> Williams, Exh. No. BNW-1T at 16. Order 08 was subsequently entered March 10, 2006, in Docket UE-051090, adding commitments based on the Commission's adoption of the "most favored state clause." These additional commitments did not affect Commitment 37.

<sup>146</sup> *Id.* The suspension period in this case ends April 3, 2011.

<sup>147</sup> *Id.* at 17.

<sup>148</sup> Duvall, Exh. No. GND-1T at 8. The general operations of the GRID model are also described in Duvall, Exh. No. GND-2.

- An Oracle-based data repository for storage of all inputs
- A Java-based software engine for algorithm and optimization processing
- Outputs that are exported in Excel readable format
- A web browser-based user interface<sup>149</sup>

104 Expert witnesses from Staff and ICNU devote considerable portions of their testimony on net power costs to criticisms of the GRID model's limitations and PacifiCorp's choice of inputs and settings used in it.<sup>150</sup> Much of the debate on the contested adjustments analyzed below involves the question of whether the GRID model adequately estimates power costs and whether the GRID model performs well enough to determine certain costs either "inside GRID" or "outside GRID."<sup>151</sup>

105 In assessing the differing views of the experts, we are mindful of the fact that the GRID model and its data bases are designed, built, and supplied by PacifiCorp. Accordingly, in addition to the general burden of proof the Company bears to demonstrate that its overall rates are appropriate, the Company has the obligation to demonstrate that the *Company's* costs are appropriately captured in the *Company's* model. If a given cost is challenged by another party, PacifiCorp cannot satisfy its burden of proof by responding only to the effect that "the GRID model captures the costs correctly."

#### **b. Arbitrage Sales Margin**

106 There are two types of short-term transactions or "arbitrage sales" at issue in this case. The first, called locational arbitrage, is the buying of power at one location and the simultaneous selling of power at another location. The second type of transaction is an energy trading opportunity that occurs when the Company has already entered into what may be a longer term position on energy or sales but then executes short-term purchases or sales to optimize revenue in response to daily or weekly prices.<sup>152</sup>

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<sup>149</sup> Duvall, Exh. No. GND-2 at 1 - 16.

<sup>150</sup> See, e.g., Buckley, APB-1CT at 5 - 9; Falkenberg, RJF-1T at 56.

<sup>151</sup> See, e.g., Buckley APB-1CT at 6, 12; Falkenberg, RJF-1CT at 9, 28.

<sup>152</sup> Buckley, Exh. No. APB-1CT at 5 - 6.

- 107 *Positions of the Parties.* The Company contends that its GRID model accurately determines resource dispatch including “balancing market purchases and sales necessary to balance and optimize the system and net power costs taking into account the constraints of the Company’s system in the west control area.”<sup>153</sup>
- 108 Staff claims the model does not include any revenue from arbitrage sales. To reflect these transactions, Staff proposes an “arbitrage sales adjustment” that increases operating revenues from power sales by \$527,315, thereby reducing NPC expenses.<sup>154</sup> Staff calculates its adjustment as 90 percent of the four-year average of the transactions to arrive at its \$527,315 adjustment. It argues that a 10 percent “profit-sharing” with PacifiCorp maintains the Company’s incentive to maximize the use of its transmission system.<sup>155</sup>
- 109 ICNU makes a comparable “added sales margins” adjustment that increases operating revenues from power sales and reduces NPC by \$585,874.<sup>156</sup> ICNU explains that its adjustment is larger because it does not include Staff’s 10 percent “profit sharing” deduction in its calculation.<sup>157</sup>
- 110 In rebuttal testimony, the Company opposes both adjustments arguing that the GRID’s system of balancing sales and purchases act as a proxy for future short-term firm sales and purchases, including arbitrage transactions.<sup>158</sup>
- 111 *Commission Decision.* Staff and ICNU’s proposed adjustments raise the essential question of all power cost modeling: how well does the model capture expected expense and revenues of actual utility operations? The Company acknowledges that

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<sup>153</sup> Duvall, Exh. No. GND-2 at 1 - 2.

<sup>154</sup> Buckley, Exh. No. APB-1CT at 9.

<sup>155</sup> *Id.* at 8.

<sup>156</sup> Falkenberg, Exh. No. RJF-1CT at 2.

<sup>157</sup> *Id.*

<sup>158</sup> Duvall, Exh. No. GND-5T at 31 - 32.

arbitrage sales occur and argues that the system balancing in the GRID model acts as a proxy for these sales. The question is whether the GRID model represents short-term sales. In this case, we are convinced that it does not.

112 We should accept proxy results only if no better alternative is available. In this case, we have a better alternative: the four-year average of actual operations. PacifiCorp does not argue that Staff's and ICNU's numbers are not representative of the sales it would anticipate during the term rates will be in effect. Accordingly, we accept ICNU's calculation of arbitrage sales.

113 The next issue is whether all arbitrage sales revenues should be used to offset net power costs, as proposed by ICNU, or whether a portion of those revenues should be "shared" with the Company, as proposed by Staff. As a general rule, we do not believe it necessary to provide monetary incentives to utilities for properly managing assets under their control. Having found the expected revenue to be reasonable given the Company's history of actual sales, we believe the Company has sufficient reason to continue to prudently manage its sales opportunities. Should it do otherwise, the Company would risk incurring a loss from this adjustment because it has the effect of reducing NPC. For this reason, we do not accept Staff's "profit sharing" proposal, and we increase operating revenues by \$585,874.

### **c. Seattle City Light (SCL) Stateline Contact**

114 PacifiCorp entered into contracts with Seattle City Light (SCL) to receive real time output from SCL's share of the Stateline wind farm. The Company returns power two months later. The SCL Stateline contract terminates during the rate year on December 31, 2011.<sup>159</sup>

115 *Commission Decision.* During the hearing, the parties reached agreement on how to address the SCL Stateline Contract in this case.<sup>160</sup> The parties concur that the contract should be treated in the manner presented in Company's rebuttal testimony and agree to reduce NPC expense by \$349,229. We accept the parties' agreement on this issue

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<sup>159</sup> Buckley, Exh. No. APB-ICT at 9.

<sup>160</sup> Exh. No. 15C, Response to Bench Request No. 3.

with the understanding that this agreement, like all settlement agreements, may not be used as a precedent in future proceedings.

**d. Wind Inter-hour Integration Costs**

116 Wind integration costs refer to the costs the Company incurs to manage wind-generated power in conjunction with its other power sources. The Company includes two categories of wind integration charges: one for the Company's wind resource located in the Bonneville Power Administration's (BPA) control area and another one for the wind resources located in the Company's West Control Area.<sup>161</sup> Staff and ICNU proposed adjustments to the Company's inter-hour wind integration charges,<sup>162</sup> and in its rebuttal testimony, the Company accepted all Staff and ICNU's inter-hour adjustments except for those that relate to the SCL Stateline exchange contract, reducing operating expense by \$220,983.

117 *Commission Decision.* The Company's acceptance of all inter-hour wind integration adjustments, save the one associated with the SCL Stateline contract, removes the majority of these costs from dispute. The inter-hour wind integration costs associated with the SCL Stateline Contract were resolved according to the terms expressed in Section II.C.1.c above.<sup>163</sup> We accept the parties' agreement on this issue, again with the understanding that this agreement may not be used as a precedent in future proceedings.

**e. Wind Intra-Hour Integration Cost**

118 *Positions of the Parties.* The Company also includes intra-hour wind integration costs in its NPC calculation. However, rather than determining these costs through its GRID model, PacifiCorp uses separate wind integration studies based on the Company's 2008 Integrated Resource Plan.<sup>164</sup> Since the last rate case, the Company

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<sup>161</sup> Duvall, Exh. No. GND-1T at 15 - 16.

<sup>162</sup> Buckley, Exh. No. APB-1CT at 22 -23; Falkenberg, Exh. No. RJF-1CT at 35. This opposition is discussed in detail in the subsequent subsection d entitled "Wind Intra-hour Integration Costs." As a result of the parties' settlement on wind inter-hour integration costs, discussed below, these arguments are essentially moot and will not be repeated in the subsection.

<sup>163</sup> Exh. No. 15C, Response to Bench Request No. 3.

<sup>164</sup> Duvall, Exh. No. GND-1T at 6.

asserts its costs for wind integration increased from \$1.15 per megawatt hour (MWh) to \$6.97 per MWh.<sup>165</sup>

119 Staff states that the Commission should remove all wind integration costs because the Company's wind integration costs fail to pass the known and measurable standard and the facilities do not provide power to PacifiCorp.<sup>166</sup> Based on its review of four non-Company owned facilities,<sup>167</sup> Staff recommends removing all intra-hour wind integration costs for these facilities from NPC.

120 Staff questions the reliability of the Company's data showing the cost increase since the last rate case.<sup>168</sup> The study updating these costs, though anticipated in August 2010, was not completed until September 2010. Should these costs be updated now, the Company claims that they would be even higher, \$9.01 MWh.<sup>169</sup> Staff states that it has not had the opportunity to review or analyze the updated study because it was filed late and shortly before Staff's testimony was due in this case. Because of its complexity and numerous revisions, Staff concludes that the study does not produce integration costs that meet the Commission's known and measurable standard. Staff proposes removal of wind integration costs for plants from which Washington ratepayers receive no power and which, it alleges, are not known and measurable.

121 ICNU also supports removing PacifiCorp's intra-hour wind integration costs for non-SCL wind farm costs, Oregon QFs, Campbell wind farm, as well as for the SCL Stateline contract the parties reached a compromise on. ICNU opposes non-SCL wind farm costs and Campbell wind farm costs because the Company's Open Access Transmission Tariff (OATT) doesn't have a provision for charging the wind customer

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<sup>165</sup> *Id.*

<sup>166</sup> Buckley, Exh. No. APB-1CT at 22 – 23.

<sup>167</sup> These projects are the SCL Stateline Wind Farm, the non-SCL owned Stateline project, the Campbell Wind Farm, and the Oregon Qualifying Facilities. *See* Buckley, Exh. No. APB-6 at 1.

<sup>168</sup> Buckley, Exh. No. APB-1CT at 22.

<sup>169</sup> *Id.*

for wind integration services.<sup>170</sup> ICNU also states that generation and costs for QFs are under the WCA and are assigned to each WCA state.

122 In a separate adjustment, ICNU supports removing PacifiCorp's intra-hour wind integration costs for Company-owned wind projects,<sup>171</sup> and argues that these costs were determined outside the GRID model.<sup>172</sup> ICNU also contends, for a number of reasons, that the costs are inaccurate and high.<sup>173</sup> It proposes its adjustment based on a wind cost derived from ICNU's use of the GRID to determine intra-hour wind integration costs for Company-owned wind resources.<sup>174</sup>

123 In rebuttal testimony, the Company proposes a compromise approach that, for this case, would use ICNU's GRID-based intra-hour integration cost projections for Company-owned resources costs. Rather than push for a decision in this docket, it would defer Commission approval of the proper modeling of wind integration in GRID to a future proceeding in which all parties have the opportunity to thoroughly evaluate intra-hour wind integration modeling proposals.<sup>175</sup>

124 In its testimony and its brief, PacifiCorp also argues that it incurs these wind integration costs pursuant to the Federal Energy Regulatory Commission's (FERC) OATT.<sup>176</sup> Because FERC has exclusive authority over these costs pursuant to the Federal Power Act, states may not conclude that these rates are unreasonable and must pass them through to the retail customers.<sup>177</sup> Staff and ICNU respond that this is not an instance in which the Commission is failing to pass through a federally

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<sup>170</sup> Falkenberg, Exh. No. RJF-1CT at 45 – 46.

<sup>171</sup> *Id.* at 42 - 44.

<sup>172</sup> *Id.* at 35.

<sup>173</sup> *Id.* at 36 - 37 (listing eleven reasons).

<sup>174</sup> Falkenberg, Exh. No. RJF-1CT at 42 - 44.

<sup>175</sup> Duvall, Exh. No. GND-5T at 28.

<sup>176</sup> Duvall, Exh. No. GND-5T at 44 – 47, PacifiCorp Initial Post-Hearing Brief ¶¶ 51 – 52.

<sup>177</sup> PacifiCorp Initial Post-Hearing Brief ¶¶ 81 – 82.

approved rate. Rather, these are interstate costs and belong in the federal jurisdiction.<sup>178</sup>

125 *Commission Decision.* We accept Staff and ICNU’s proposal to remove the intra-hour wind integration costs for non-owned facilities. All costs for which a utility seeks recovery must be known and measurable. In this case, the Company calculated these intra-hour wind integration costs outside its own power supply model and presented an updated study that did not afford Staff and ICNU a reasonable opportunity for review. The wind integration costs at issue represent a six-fold increase in one year, and if updated, would reflect an even greater increase. Thus, the Company bears the burden to demonstrate that the substantial increase is warranted. We conclude that PacifiCorp failed to satisfy its burden to demonstrate that these costs are known and measurable.

126 Nor can PacifiCorp evade its evidentiary burden by claiming that the costs are associated with a FERC tariff. A utility cannot use a federal tariff to justify its failure to quantify the costs for which it seeks recovery in a state proceeding. We agree with Staff and ICNU that the Supremacy Clause of the United States Constitution does not require the Commission to pass through these costs. FERC has not set a wholesale wind integration rate under the Company’s OATT, and accordingly, PacifiCorp’s remedy is to file with FERC for an amendment to its OATT. Indeed, PacifiCorp indicated that it planned to do just that.<sup>179</sup> These costs should be borne by the third-parties who create these costs, not by Washington ratepayers who do not receive the power generated at these facilities. Rejecting these intra-hour wind integration costs reduces NPC expense in Washington by \$518,692.<sup>180</sup>

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<sup>178</sup> Staff Post-Hearing Reply Brief ¶¶ 68-72; ICNU Post-Hearing Reply Brief ¶¶ 13-19.

<sup>179</sup> Duvall, Exh. No. GND-5T at 46.

<sup>180</sup> Staff Initial Post-Hearing Brief, Appendix A at 1.



**f. Sacramento Municipal Utility District (SMUD) Shaping Contract**

127 The Sacramento Municipal Utility District (SMUD) purchases power under a contract from PacifiCorp, and the Company includes the cost of this contract in its GRID model.

128 *Positions of the Parties.* Staff argues that SMUD has some discretion regarding the timing of power deliveries under the contract, and the GRID model overstates the contract's cost by assuming that power will not be delivered in the months of April, May and June, when power costs are typically lower.<sup>181</sup> Using historic data of PacifiCorp's actual power deliveries to the SMUD, Staff produces an adjustment that lowers normalized net power costs, which takes into account deliveries that would be made in lower cost months.<sup>182</sup> Staff's adjustment lowers the Company's NPC by \$554,460.<sup>183</sup>

129 ICNU also reduces the costs associated with the SMUD contract and adjusts the NPC by \$458,223.<sup>184</sup> However, ICNU's rationale differs from Staff's adjustment in two ways.<sup>185</sup> First, ICNU decreases the quantity of energy taken under the contract, arguing that PacifiCorp overstates the energy delivered under the contract by 45,500 MWh, resulting in a reduction of Washington allocated power costs of \$38,504.<sup>186</sup> ICNU also differs from Staff in that it uses the GRID model to calculate a dollar amount from the historic average of energy delivered to the SMUD under the contract.<sup>187</sup> Staff, on the other hand, uses a historic average to calculate a dollar

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<sup>181</sup> Buckley, Exh. No. APB-1CT at 11 - 12.

<sup>182</sup> *Id.* at 13.

<sup>183</sup> *Id.* at 14.

<sup>184</sup> Falkenberg, Exh. No. RJF-1CT at 2.

<sup>185</sup> Falkenberg, Exh. No. RJF-1CT at 30 – 31; Exh. No. RJF-8CT at 3.

<sup>186</sup> *Id.* at 30 - 31.

<sup>187</sup> Falkenberg, Exh. No. RJF-8CT at 3.

amount, but does not run its adjustment through the model.<sup>188</sup> Should the Commission accept the reasoning behind Staff and ICNU's adjustments, they recommend that it order the Company to model the contract within GRID with deliveries more in line with historical deliveries.<sup>189</sup>

130 In rebuttal testimony the Company agrees with ICNU's adjustment to the level of allowed energy sales under the contract, which results in an increase to operating revenue of \$19,039.<sup>190</sup> However, for three reasons, the Company disagrees with the use of historic data for modeling the SMUD contract costs.<sup>191</sup>

131 First, the Company asserts that, for normalization purposes, the model assumes that the third party (SMUD) that controls the timing of energy deliveries will maximize the value of the contract and take power at the time most economical to it.<sup>192</sup> The Company argues further that Staff and ICNU optimize flexible resources when the effect is to lower NPC, but chooses not to when it raises NPC. It contends that third party contracts should be treated consistently, and flexible resources should be optimized whether the Company is selling or buying power.<sup>193</sup>

132 Second, the Company argues the proposed adjustment departs from its process of modeling power costs on a normalized basis.<sup>194</sup> It claims that it cannot model constraints, forward price curves, or loads used by the counterparties because it cannot get that proprietary data and can only assume that all participants in the same market are rational and will exercise their contractual rights in a manner that lowers their costs.<sup>195</sup>

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<sup>188</sup>Buckley, Exh. No. APB-1CT at 13 - 14.

<sup>189</sup> Buckley, Exh. No. APB-1CT at 13 - 14, Falkenberg, Exh. No. RJF-8CT at 3.

<sup>190</sup>Dalley Exh. No. RBD-6 at 12.6.6.

<sup>191</sup> Duvall, Exh. No. GND-5CT at 36 - 40.

<sup>192</sup> Duvall, Exh. No. GND-5T at 37.

<sup>193</sup> *Id.* at 36.

<sup>194</sup> *Id.*

<sup>195</sup> *Id.* at 37.

133 Third, the Company contends that the model includes both the firm and the provisional features of the contract but that ICNU only addresses the firm feature in its adjustment.<sup>196</sup> The Company states that the contract's provisional feature allows SMUD the right to take provisional power under the terms of the contract and return the power to the Company the following year.<sup>197</sup> It argues that an examination of the contract's provisional and firm power features would support the GRID's conclusions as to power deliveries made to the SMUD under the contract.<sup>198</sup>

134 *Commission Decision.* We are asked again to select between the GRID model's results and an adjustment based on historic normalized data. A sharp contrast exists between actual deliveries under the SMUD contract and those projected by the GRID model, and the Company's statement that it cannot model constraints, forward price curves, or loads used by a third-party further weakens the support for using the model's results. When confronted with similar decisions, we give greater weight to actual results unless they are proven to be unreliable. The Company raised questions about how the SMUD would take power under the agreement but did not challenge the actual data on which Staff and ICNU rely.

135 We conclude that the Company did not demonstrate that the GRID effectively models the SMUD contract's actual impacts. The Company attempts to bolster its position by citing the importance of using SMUD's pattern of use under the provisional call option to determine SMUD's pattern of use under the demand portion of the contract. This argument is misplaced because PacifiCorp does not propose to use provisional sales in its net power costs. The real question is how to determine the effect of demand deliveries made under the SMUD contract. To answer this question, we conclude that Staff and ICNU's use of actual contract data to predict an outcome is correct and reasonably represents the SMUD's demand under the contract.<sup>199</sup>

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<sup>196</sup> *Id.* at 39.

<sup>197</sup> *Id.*

<sup>198</sup> *Id.*

<sup>199</sup> The Utah Commission has concluded similarly. *See* ICNU's Post-Hearing Brief. ¶62.

136 Accordingly, we require PacifiCorp to incorporate Staff's SMUD contact demand shape into the balancing adjustment required by this Order. We recognize that the amount of this adjustment cannot be calculated with specificity until all changes to the GRID model run are incorporated, but we estimate this adjustment will lower NPC expense by \$554,460.

**g. Colstrip Outage**

137 PacifiCorp generates a significant amount of its power at its Colstrip coal plant, which like all plants, is subject to outages. The issue is how to compute the average outage rate for this plant as part of the Company's NPC.

138 *Positions of the Parties.* In 2009, PacifiCorp experienced a seven-month outage at Unit 4 of the Colstrip coal plant.<sup>200</sup> The Company proposes to use the period 2006 through 2009 as the base for computing the average outage rate for this plant.<sup>201</sup>

139 Staff believes that including the extraordinary 2009 period in the calculation of the plant's average outage rate would skew the outage average upward.<sup>202</sup> This would increase the Company's normalized net power costs, as the GRID model would seek to find replacement power, which is available but at a higher cost. In the alternative, Staff uses an average outage rate of eight percent in its calculation of Colstrip availability and contends that eight percent better represents the outage rates experienced by other utilities that own a share of the Colstrip plants.<sup>203</sup> Staff's adjustment reduces operating expense by \$342,889.<sup>204</sup> ICNU also argues against including the 2009 outage in the plant's average outage calculation, concluding that the long outage in 2009 is "an extremely rare event" and not "likely to recur every

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<sup>200</sup> Colstrip Unit 4 is a baseload facility that provides low cost power.

<sup>201</sup> Duvall, Exh. No. GND-5T at 50.

<sup>202</sup> Buckley, Exh. No. APB-1CT at 15.

<sup>203</sup> *Id.* at 17. Here Staff testifies that its eight percent outage rate is similar to that experienced by Avista.

<sup>204</sup> *Id.* at 18.

four years.<sup>205</sup> Therefore, ICNU proposes to cap the length of the outage at 28 days,<sup>206</sup> resulting in an operating expense reduction of \$376,492.<sup>207</sup>

140 In rebuttal testimony, the Company argues that Staff and ICNU's adjustments are unfair because they selectively remove data that would lower forced outage rates and thereby eliminate the opportunity for the forced outage rates to fluctuate with actual data.<sup>208</sup>

141 *Commission Decision.* The dispute before us is how to set an annual outage rate in light of a single, large, anomalous event. We agree with Staff that the purpose of establishing an annual outage rate is to represent expected outage levels during the rate year. PacifiCorp does not dispute that the approximately seven month outage is an anomaly. ICNU's proposal to remove all outages longer than 28 days addresses the issue, but lacks substantial justification.

142 While Staff's proposal is not elaborately described, we conclude that it is a better approach than either that proposed by the Company or ICNU and, most importantly, is more predictive of what may occur in the future. To calculate the impact of Staff's eight percent outage rate, we require the Company to re-run the GRID model using this outage rate for Colstrip Unit 4. Again, we recognize that the dollar amount of this adjust may vary as a result of other changes to the GRID model, and estimate that it will reduce NPC by \$342,889.

#### **h. Direct Current (DC) Intertie**

143 PacifiCorp currently has long-standing agreement with the BPA that provides transmission capacity on BPA's Direct Current (DC) Intertie from the Nevada-Oregon Border (NOB) to the Buckley substation. PacifiCorp has BPA network

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<sup>205</sup> Falkenberg, Exh. No. RJF-1CT at 50.

<sup>206</sup> *Id.* at 50. Mr. Falkenberg cites, without elaboration, a recommendation by the Company in an Oregon proceeding as the basis his recommendation here.

<sup>207</sup> *Id.* at 2.

<sup>208</sup> Duvall, Exh. No. GND-5T at 49 - 50.

transmission service from the Buckley substation to its system loads, which enables it to make power purchases at the NOB.<sup>209</sup>

144 *Positions of the Parties.* PacifiCorp states that both Company-owned transmission capacity and transmission capacity provided by contracts with third parties are properly included in the West Control Area modeling so long as the capacity is needed to transmit power from and to locations in the West Control Area. Specifically, the Company contends that the costs of the BPA's DC Intertie are appropriately included in the GRID model.

145 Staff argues that the costs related to the transmission contract securing rights in BPA's DC intertie should be removed because the Company is unlikely to use the capacity during the year rates would take effect because of the high price of the power in California.<sup>210</sup> As support, Staff points to the fact that PacifiCorp does not include purchases at the NOB in its GRID model.<sup>211</sup> Therefore, Staff proposes a \$1,057,130 reduction in NPC expense.<sup>212</sup>

146 ICNU agrees with Staff and recommends removing the DC intertie costs because the DC intertie contract is not used and useful,<sup>213</sup> and also argues that such purchases are unlikely to occur during the rate year.<sup>214</sup> ICNU proposes a \$1,057,130 reduction in NPC.<sup>215</sup>

147 In rebuttal testimony, the Company argues that the DC intertie contract was entered into prudently and although the GRID model does not foresee energy transactions at the NOB during the test year, the prudence of the Company's actions should be

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<sup>209</sup> Buckley, Exh. No. APB-1CT at 18.

<sup>210</sup> *Id.* at 19.

<sup>211</sup> *Id.*

<sup>212</sup> *Id.*

<sup>213</sup> Falkenberg, Exh. No. RJF-1CT at 33 – 34.

<sup>214</sup> *Id.* at 34.

<sup>215</sup> Falkenberg, Exh. No. RJF-1CT at 2.

judged based on the information that was known at the time the contract was executed, not on hindsight.<sup>216</sup>

148 *Commission Decision.* PacifiCorp's evidence and arguments focus on whether the contract was prudent when it was executed. However, we do not need to answer that question in this Order. Even if we assume that the contract was prudent at its inception the Company has an ongoing obligation to manage the resource under contract to provide a benefit to the Company and its ratepayers. PacifiCorp has failed to demonstrate that it does so.

149 Both Staff and ICNU testify that the contract is not expected to be used during the rate year to support the West Control Area, and thus no benefits are likely to materialize from the transmission capacity under the contract. The parties base their conclusions on the Company's failure to use the DC intertie capacity during the test year. As to its future use, they point to the absence of NOB contracts in the Company's GRID model as further support for their conclusion that the contract's capacity will not be used during the rate year.

150 We find Staff's and ICNU's testimony and arguments to be compelling. Generally, for a resource to be included in rates, it must be found to be used and useful. This is not to say that every component of the Company's system has to be used to provide service at all times.<sup>217</sup> However, the testimony here raises serious doubt as to the continued usefulness of the DC intertie capacity – doubt that PacifiCorp fails to address, much less resolve.

151 There is a point when facilities or even contracts such as this have no demonstrated or foreseeable need. It is at this point that such capacity should be retired or written off the books. We are not convinced that now is the time for such action, and we accept the Company's rationale that the DC intertie capacity could be useful in the future. The Company, however, must do more than state that the facility might be used at some unspecified time to justify including this resource in rates.

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<sup>216</sup> Duvall, Exh. No. GND-5T at 42.

<sup>217</sup> For example, peaking resources may only be used for short periods of time during a given period. We allow these in rates because the need for peaking capacity is fundamental to the efficient and reliable operation of the system.

152 If the contract is not being used by the Company, it has an obligation to market its available transmission capacity in an effort to recover some of its costs. The Company proffers no testimony along this line. For these reasons, we conclude that PacifiCorp failed to demonstrate that the DC intertie contract would provide benefits to Washington ratepayers during the rate year. Therefore, we adopt the adjustments presented by Staff and ICNU and reduce NPC expense by \$1,057,130.

**i. Idaho Point-to-Point (PTP) Transmission Contract**

153 The Company has a point-to-point (PTP) wheeling contract with the Idaho Power Company. The issue arises concerning the extent to which the costs associated with that contract should be included in PacifiCorp's NPC.

154 *Positions of the Parties.* Staff uses confidential information to explain the terms of this contract, arguing that despite the benefits to both the western control area and the eastern control area.<sup>218</sup> PacifiCorp assigns all the contract costs to PACW.<sup>219</sup> Staff argues that this result is inappropriate and assigns only half of the Idaho PTP transmission cost to the PACW thus reducing NPC expense by \$351,118.<sup>220</sup>

155 ICNU's adjustment likewise allocates 50 percent of the transmission contract's cost to the west control area based on the parallel treatment of other resources. It argues that because the Commission once disallowed benefits similar to those being realized by PACE in this instance, the Commission should disallow one-half of the Idaho PTP transmission contract costs at issue here.<sup>221</sup> ICNU explains that its adjustment amount differs from Staff's because it also excludes costs related to providing transmission service to isolated loads in Idaho.<sup>222</sup> ICNU's adjustment reduces expense by \$363,988.<sup>223</sup>

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<sup>218</sup> The contract refers to the western control area as "PACW" and the eastern control area as "PACE."

<sup>219</sup> Buckley, Exh. No. APB-1CT at 20.

<sup>220</sup> *Id.* at 21.

<sup>221</sup> Falkenberg, Exh. No. RJF-1CT at 32. *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket Nos. UE-061546/UE-060817, Order 08, ¶¶ 53-54 (June 21, 2007).

<sup>222</sup> Falkenberg, Exh. No. RJF-1CT at 32.



156 In rebuttal testimony, the Company opposes the adjustment stating that it is a change to the WCA methodology and that *ad hoc* changes to the WCA should not be made until the five-year review of the methodology ordered by the Commission in Order 8 in Docket UE-061546.<sup>224</sup> The Company also updates its cost for the Idaho PTP contract rate arguing that if the forward price curves are updated, the matching principle requires that other costs also be updated.<sup>225</sup> The Company's update increases operating expense by \$166,501.<sup>226</sup>

157 In its brief, the Company states that ICNU agreed that some PTP contract costs had been removed in the Company's initial filing.<sup>227</sup> There are two parts to the Idaho PTP transmission contract.<sup>228</sup> The first part relates to the Idaho PTP east portion and the Company removed these costs. The second part relates to the Idaho PTP west portion that is included in the Company's initial filing and is subject to ICNU's proposed adjustment.

158 The Company agrees with the portion of ICNU's adjustment that removes costs associated with providing transmission service to isolated loads in Idaho. PacifiCorp represents that removing those costs reduce operating expenses by \$12,836.<sup>229</sup>

159 *Commission Decision.* We reject PacifiCorp's argument that the proposed adjustment is an *ad hoc* change to the WCA methodology that cannot be undertaken until the WCA's five-year review. We also reject the Company's assertion that the parties' adjustments run contrary to the principles underlying the WCA methodology. It is

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<sup>223</sup> *Id.* at 2.

<sup>224</sup> Duvall, Exh. No. GND-5T at 32 – 33. *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket Nos. UE-061546/UE-060817, Order 08, ¶¶ 53-54 (June 21, 2007).

<sup>225</sup> *Id.* at 17.

<sup>226</sup> Dalley Exh. No. RBD-6 at 12.6.6.

<sup>227</sup> PacifiCorp's Initial Post-Hearing Brief ¶ 77.

<sup>228</sup> Falkenberg, TR 655.

<sup>229</sup> Duvall, Exh. No. GND-5T at 26, Dalley Exh. No. RBD-6 at 12.6.6.

not inconsistent with that methodology to allocate costs of a resource between the PACW and PACE, so long as both divisions realize benefits. The costs of PACW resources included in NPC should be offset to reflect the benefits realized by the PACE when it uses PACW resources.

160 We conclude that Staff and ICNU's arguments for removing one-half the expenses associated with the Idaho PTP west portion of the transmission contract are persuasive. These parties demonstrate that both the PACW and PACE realize benefits under the contract, so the costs should not be assigned exclusively to the PACW. The Commission observes that the Company provides no evidence supporting the claim that half the costs associated with the west portion of the contract have been removed. ICNU's explanation at hearing that the adjustment is based on the west portion of the Idaho PTP contract costs is complete and convincing. We conclude that one-half of the Idaho PTP's *updated* costs, \$753,840, should be removed from NPC. We also accept the undisputed adjustment to remove \$12,836 in costs associated with the providing transmission services to isolated loads in Idaho prior to the removal of one half of the contract as ordered.

#### **j. Price Update**

161 The parties agreed to use the December 31, 2010, forward prices in the balancing adjustment to NPC.<sup>230</sup> We accept the use of these forward prices for the purpose of this case.

#### **k. Logic Screen**

162 *Positions of the Parties.* ICNU argues that there is a logic error in the GRID model that results in an excessive number of start-ups and shut-downs of the Company's gas fired resources.<sup>231</sup> Accordingly, ICNU proposes a different screening logic for the start-up (dispatch) of plants in GRID and proposes an accompanying adjustment outside of NPC to the variable O & M costs for thermal plants with dispatch affected by the proposed logic screening methodology.<sup>232</sup> ICNU's adjustment for logic screen, not including the O&M adjustment, reduces expense by \$973,337.<sup>233</sup>

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<sup>230</sup> Exhibit 15C, Response to Bench Request No. 3.

<sup>231</sup> Falkenberg, Exh. No. RJF-1CT at 10 - 11.

<sup>232</sup> *Id.* at 14.

163 In rebuttal testimony, the Company accepts ICNU’s proposed logic screen but does not accept that ICNU’s conclusion that its screening logic changes incremental fixed O&M expenses included in the test year.<sup>234</sup> It argues that ICNU “provides no explanation of its adjustment or evidence to support it.”<sup>235</sup> The net effect on revenues and expenses of the Company’s adjustment is a reduction in NPC of \$239,636.<sup>236</sup>

164 *Commission Decision.* We conclude that the undisputed modification to the logic screen is reasonable and should be accepted. We require the Company to use the modified logic screen in its balancing adjustment. However, ICNU failed to demonstrate that PacifiCorp made an incremental adjustment to O & M or its calculation of NPC to reflect the costs of additional dispatches. Therefore, we reject ICNU’s adjustment to the O&M costs for thermal plants.

### I. Eastern Market Sale

165 *Positions of the Parties.* ICNU states that PacifiCorp includes sales to the eastern control area when it models PACW power costs. ICNU proposes two adjustments that it argues would better reflect the benefits to the PACW of energy transactions between the western and eastern markets. ICNU’s first adjustment is intended to capture the reliability benefits of utilizing excess generation to supply PACE. The second adjustment is intended to better capture the advantage of the price difference between prices at Mid-C and the eastern markets.<sup>237</sup> ICNU also contends that the GRID only models sales from the west control area to the east control area, and not purchases; does not properly consider hourly prices and off-peak sales; and only considers on-peak sales, ignoring opportunities for off-peak transactions that

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<sup>233</sup> *Id.* at 2.

<sup>234</sup> Duvall, Exh. No. GND-5T at 22, 55 - 56.

<sup>235</sup> *Id.* at 56.

<sup>236</sup> Dalley, Exh. No. RBD-6 at 12.6.6.

<sup>237</sup> Falkenberg, Exh. No. RJF-1CT at 18 - 19.

frequently exist.<sup>238</sup> ICNU's two adjustments increase operating revenue by \$502,308.<sup>239</sup>

166 ICNU contends that Commission precedent supports its adjustments because the Commission decision on the WCA methodology supports the "indirect inclusion of eastside benefits and costs if purchases or sales between the control areas are economic."<sup>240</sup>

167 The Company opposes these adjustments arguing that *ad hoc* changes to the WCA cost allocation methodology should not be allowed until the five-year review of the methodology ordered by the Commission is completed.<sup>241</sup> The Company also argues that ICNU's adjustment to eastern market modeling is flawed because it was done outside the GRID and ignores the impact of serving the assumed sale (the cost of electricity production). The Company proposes that if the Commission accepts this adjustment it should be run inside the GRID to determine its impact on NPC. The Company also asserts that ICNU proposes to adjust wheeling expense from the Colstrip plant, but allows the energy to pass through the transmission to the east side.<sup>242</sup> Finally, the Company argues that ICNU relies on benefits created after ICNU fabricates, within the model, an energy shortage for the eastern control area.<sup>243</sup> The Company recommends the Commission reject both adjustments.<sup>244</sup>

168 *Commission Decision.* We agree with PacifiCorp that ICNU did not provide adequate support for its first adjustment. ICNU's method for adjusting the model's operation

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<sup>238</sup> *Id.* at 16.

<sup>239</sup> *Id.* at 2.

<sup>240</sup> *Id.* at 16; *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket Nos. UE-061546/ UE-060817, Order No. 08. ¶ 47 (June 21, 2007).

<sup>241</sup> Duvall, Exh. No. GND-5T at 32– 33.

<sup>242</sup> *Id.* at 35.

<sup>243</sup> *Id.*

<sup>244</sup> *Id.*

to derive a dollar figure for the value of the reliability benefit is not adequately explained.

169 We do find merit in ICNU's second adjustment. PacifiCorp's argument that it is an *ad hoc* adjustment to the WCA methodology misses the mark here as much as it did in our discussion of the Idaho point-to-point contract. The Company fails to defend its use of only on-peak hours in its eastern sales calculations. The Company also fails to defend or refute its use of monthly average hourly prices for the PACE, prices used to calculate the economics of a sale. We conclude that ICNU's second adjustment should be accepted thereby reducing NPC by approximately \$225,248.

**m. Eastern Control Area Transmission Costs- Colstrip East**

170 *Positions of the Parties.* The Company splits in half the transmission costs of the transmission capacity from Colstrip to its entire system (both PACW and PACE) and includes half the costs of the entire transmission system in its Washington-allocated NPC. ICNU proposes a reduction in this wheeling expense to reflect the proportion of the transfer capacity from Colstrip to PacifiCorp that is attributable to connecting Colstrip to the PACW.<sup>245</sup> Utilizing a current topology map of PacifiCorp's GRID transmission, ICNU divides the Colstrip to PACW transfer capacity by the total Colstrip to PacifiCorp transfer capacity and uses that factor to allocate a portion of the total wheeling expense to the PACW. ICNU's adjustment reduces NPC expenses by \$45,690.<sup>246</sup>

171 In rebuttal, the Company opposes the adjustment arguing that it is a change in the WCA methodology and that *ad hoc* changes should not be allowed. The Company recommends that changes be deferred to the Commission's five-year review of the WCA methodology.

172 *Commission Decision.* As with the Idaho point-to-point contract, we are not persuaded by the Company's argument that adjustment is an *ad hoc* change to the WCA methodology that cannot be undertaken now. We reiterate that this position is contrary to the principles underlying the WCA methodology: that is, those burdens

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<sup>245</sup> Falkenberg, Exh. No. RJF-1CT at 31.

<sup>246</sup> *Id.*

align with benefits, and only those costs attributable to the western control area should borne by PacifiCorp' customers in that area. The costs of resources included in PACW net power costs should be proportional to the benefits the PACW realizes from those resources. ICNU presents a reasonable cost/benefit ratio based on the transmission capacity to the PACW and PACE. We accept ICNU's proportional split of transmission costs, thereby reducing NPC by \$45,690.

**n. Non-Firm Transmission**

- 173 *Positions of the Parties.* ICNU proposes an adjustment to include non-firm transmission in the dispatch in GRID, as the Company has done in other states.<sup>247</sup> ICNU's adjustment reduces operating expense by \$159,576.<sup>248</sup>
- 174 In rebuttal, the Company agrees to ICNU's adjustment but argues that if non-firm transmission is included, short-term firm transmission should also be included and both should be modeled the same way.<sup>249</sup> According to the Company, including both short-term firm and non-firm transmission *increases* the NPC by \$274,089.<sup>250</sup>
- 175 *Commission Decision.* We reject both adjustments. There is insufficient evidence in this record to support including a non-firm transmission adjustment because there is no explanation of whether or not doing so in the same manner as short-term firm transmission is a more accurate modeling of the NPC. It is clear in the record who benefits from the adjustments, but this is not a sufficient basis for a decision. The Company's proposal to include short-term firm transmission with ICNU's proposed adjustment fails to address the question of how the model's accuracy is improved over the method the Company uses in its initial filing. The Commission seeks greater accuracy in the NPC modeling. Failing to find explanations of that in the record, we cannot accept these adjustments. The Company must file its balancing adjustment using the Company's initial calculation for short-term firm transmission and excluding non-firm transmission.

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<sup>247</sup> Falkenberg, Exh. No. RJF-1CT at 34.

<sup>248</sup> *Id.* at 2.

<sup>249</sup> Duvall, Exh. No. GND-5T at 16 - 27.

<sup>250</sup> Dalley Exh. No. RBD-6 at 12.6.4.

**o. Planned Outage Schedule**

176 *Positions of the Parties.* PacifiCorp uses actual outages in a four year period ending in 2009 to predict outages in the rate year.<sup>251</sup> ICNU proposes an adjustment based on revised timing for planned plant outages for Colstrip Unit 4 and Hermiston generation station.<sup>252</sup> ICNU argues that PacifiCorp plans outages for periods of least-cost replacement power but such timing is not reflected in the assumptions in GRID.<sup>253</sup> ICNU argues that the termination of the low cost gas contract that PacifiCorp uses to supply the Hermiston plant will change the operation of that plant.<sup>254</sup> Rather than operating continuously (due to the low-cost gas contract), the plant would operate on a more intermittent basis, more like the Chehalis plant.<sup>255</sup> ICNU models the Hermiston planned outage in late February and March; a time ICNU contends the economics of running the plant are least attractive.<sup>256</sup> ICNU's adjustment reduces operating expense by \$429,712.<sup>257</sup>

177 In rebuttal testimony, the Company agrees to the outage schedule change for Colstrip Unit 4 but not for the Hermiston plant.<sup>258</sup> The Company states that accepting the Colstrip Unit 4 outage schedule reduces NPC by \$119,286.<sup>259</sup> The Company argues that the Commission previously determined that it is not reasonable to assume that plant maintenance is timed to coincide with the period of lowest wholesale prices.<sup>260</sup>

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<sup>251</sup> Duvall, Exh. No. GND-5T at 29.

<sup>252</sup> Falkenberg, Exh. No. RJF-1CT at 47 - 48.

<sup>253</sup> *Id.*

<sup>254</sup> *Id.*

<sup>255</sup> *Id.*

<sup>256</sup> *Id.* at 48 - 49.

<sup>257</sup> *Id.* at 2.

<sup>258</sup> Duvall, Exh. No. GND-5T at 29 - 30.

<sup>259</sup> Dalley Exh. No. RBD-6 at 12.6.7.

<sup>260</sup> Duvall, Exh. No. GND-5T at 30; *Washington Utilities and Transportation Commission*, Docket No. UE-050482, Order No. 5 (December 21, 2005).

The Company asserts that the Hermiston plant's planned outage in 2011 is required.<sup>261</sup>

178 *Commission Decision.* We conclude that ICNU's assumption that the Company can postpone regularly-scheduled maintenance on the Hermiston plant in order to take advantage of the last few months of its gas contract is unsupported. ICNU provides no factual basis for the proposition that postponing Hermiston's maintenance is within the reasonable limits of the plant's maintenance requirements. Conversely, PacifiCorp argues convincingly that maintenance on the Hermiston plant cannot be delayed. We reject ICNU's proposed adjustment for the Hermiston plant.

179 We accept the undisputed adjustment regarding the proposed outage schedule for Colstrip Unit 4. The balancing adjustment should include the undisputed adjustment thereby reducing NPC by approximately \$119,286. The balancing adjustment should also reflect retaining the Company's maintenance schedule for Hermiston. We recognize that the specific amount of this adjustment is interdependent on other changes to the GRID model run.

**p. Jim Bridger Fuel Adjustment**

180 *Positions of the Parties.* The Company argues that Jim Bridger mine costs have decreased due to increased production and efficiency in the underground mining operation, and those cost decreases are reflected in its NPC.<sup>262</sup>

181 ICNU adjusts costs associated with the Jim Bridger coal plant arguing that the plant experiences excessive outages due to poor quality fuel.<sup>263</sup> ICNU removes all management bonuses and other employee expenses arguing that these costs should not be included until plant performance improves because the Company has direct

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<sup>261</sup> Duvall, Exh. No. GND-5T at 30.

<sup>262</sup> Duvall, Exh. No. GND-1CT at 7.

<sup>263</sup> Falkenberg, Exh. No. RJF-1CT at 53 – 54.



control over coal production for the plant.<sup>264</sup> ICNU's adjustment reduces expense by \$650,958.<sup>265</sup>

182 In rebuttal, the Company argues that the advent of less expensive underground mining at the Jim Bridger mine limits its capacity to blend coal to improve the coal quality and prevent outages.<sup>266</sup> The Company contends that it is inappropriate to remove costs associated with "low-quality" coal from the underground mine, but accept the lower coal costs that result from the favorable economics associated with underground mining.<sup>267</sup> The Company asserts that it is evaluating a storage area for surges of poor quality coal so that it can engage in better coal mixing.<sup>268</sup>

183 *Commission Decision.* We acknowledge the concern that the Company's mining operations and facility design may be the cause of more frequent outages, but ICNU fails to make a plausible argument for disallowing certain personnel costs associated with the Jim Bridger mine. ICNU does not argue that the facility's underground mining operations are not beneficial even if the costs of increased outages are factored into the equation. Nor does ICNU argue that the Company failed to consider coal blending options when it shifted to an underground mining operation. ICNU simply asserts that outages have increased due to poor coal quality. Even if we assume that ICNU's assertion is true, ICNU does not base an adjustment on the costs associated with those outages. Rather, ICNU's adjustment centers on removing bonuses, meals, and sundries provided to workers at the facility. We conclude that ICNU has not demonstrated a reasonable nexus between the outages it claims are the purpose for the adjustment, and the costs it removes. Thus, we reject the adjustment.

184 We nevertheless are concerned with increased plant outages attributable to poor coal quality. The Company appears to acknowledge this problem in its discussion of its efforts to evaluate a storage area for surges of poor quality coal. In its next general

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<sup>264</sup> *Id.*

<sup>265</sup> *Id.* at 2.

<sup>266</sup> Duvall, Exh. No. GND-5T at 51.

<sup>267</sup> Duvall, Exh. No. GND-5T at 52.

<sup>268</sup> *Id.*

rate case, the Company must present evidence of its efforts to manage coal quality at the Jim Bridger plant and explain its efforts to mitigate the adverse effects of the poor coal quality attendant to its underground mining operations.

**q. Minimum Loading and Deration Adjustment**

185 To account for outages, GRID reduces an electrical generation unit’s full capacity by “shrinking” the capacity of that unit. Thus, if there is a 20 percent outage rate at a 100 MW facility, the GRID model would view that as a plant with an 80 MW maximum capacity plant, and would not lower the plant’s low-end operating range. The adjustment to the top range, but not to the lower range decreases the generation unit’s range of variable output and thereby reduces its revenues in the model in response to short-term market prices.

186 *Positions of the Parties.* PacifiCorp states that if a generation unit is capable of cycling up or down through the usable range of its variable output during a short period of time, the Company’s GRID model compares the operating cost with the market price to determine if it can take advantage of market price opportunities.<sup>269</sup> However, ICNU argues that the model under-represents the usable range of a generation unit’s variable output.<sup>270</sup>

187 ICNU agrees that it is appropriate to represent outages by the “shrinking” or “deration” method, but ICNU proposes that the lower end of the generation unit’s operating range also be lowered by the same percentage as the top range to more accurately represent the total variable range of the generation unit.<sup>271</sup>

188 Next, ICNU applies what it describes as a “better match” between the heat rate curve and the de-rated capacity of the plant.<sup>272</sup> ICNU explains, by example, that when the heat rate curve sized for a 100 MW unit is applied to a de-rated, 80 MW unit in

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<sup>269</sup> Duvall, Exh. No. GND-2 at 1 -2.

<sup>270</sup> Falkenberg, Exh. No. RJF-1CT at 56.

<sup>271</sup> *Id.* at 55 - 56.

<sup>272</sup> *Id.* at 56 – 57.

GRID, it artificially increases the heat rate curves and the efficiency of the unit is reduced.<sup>273</sup> ICNU's adjustment reduces expense by \$299,897.<sup>274</sup>

189 In rebuttal testimony, PacifiCorp opposes both adjustments.<sup>275</sup> The Company argues that ICNU's adjustment understates the heat rate because:

The only time when the derate adjustment to the heat rate may be applicable is when the unit is dispatched at one particular level of generation—its derated maximum capacity, with the assumption that the unit would have otherwise been dispatched at its stated maximum capacity in GRID if there were not the availability “haircut”. When the unit is dispatched at any level below its derated maximum capacity, GRID has made the optimal decision to dispatch that unit at a lower and less efficient generation level, whether it has been derated or not. Therefore, derating the entire heat rate curve overstates the efficiency of the unit and understates the heat inputs.<sup>276</sup>

The Company also argues that the minimum capacity in Grid Model is the technical limit below which the generation unit can't operate.<sup>277</sup>

190 *Commission Decision.* We move with some hesitation in this particular area of power cost modeling. Both approaches before us have merit, and both have flaws. Both methods alter the match of the heat rate to the plant output level. Ultimately, the Company has the responsibility to develop a computer model to determine NPC and the burden to demonstrate that the model is well-designed.

191 We conclude that, although this is a close call, we support ICNU's proposal because it appears to better represent the usable range of a generation unit and because it appears to better match the heat rate curve with the de-rated capacity of the plant.

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<sup>273</sup> *Id.*

<sup>274</sup> *Id.* at 2.

<sup>275</sup> Duvall, Exh. No. GND-5T at 54.

<sup>276</sup> *Id.* at 53 - 54.

<sup>277</sup> *Id.* at 55.

Accordingly, we adopt ICNU's adjustment and reduce NPC expense by \$299,897. We will consider in a future case, however, an adjustment that reflects a more accurate middle ground between ICNU's and the Company's approaches to this issue.

**r. Balancing Adjustment**

192 *Positions of the Parties.* The Company, Staff, and ICNU agree that individual adjustments to the GRID model logic and inputs interact during power model runs and have interdependent effects on the final net power costs determined from the model.<sup>278</sup> Therefore, Staff and ICNU recommend that the GRID model be re-run with Commission-accepted adjustments in order to make a final determination of net power costs. The Company, Staff and ICNU agree that the GRID model needs to be re-run to reflect the most recent gas forward prices as of December 31, 2010.

193 *Commission Decision.* We conclude that PacifiCorp should re-run the GRID model with the forward prices as of December 31, 2010, and the net power costs adjustments approved above.<sup>279</sup>

**2. Renewable Energy Credit Revenue (REC)**

194 PacifiCorp generates electricity from renewable sources located in the west control area that qualify under RCW Chapter 19.285 as resources that can be used to meet the renewable portfolio standards (RPS) established by the statute. Washington's RPS require electric utilities to provide at least three percent of their load from renewable sources by January 1, 2012.<sup>280</sup> Electricity generated by qualified resources has added value in the form of renewable energy credits (RECs) that can be used to meet the RPS, sold, or, in some jurisdictions, banked for future use.<sup>281</sup> As a general rule today, PacifiCorp "unbundles" RECs from the electricity output of its qualified

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<sup>278</sup> Duvall, Exh. No. GND-5T at 16, Falkenberg, Exh. No. RJF-1CT at 61, Buckley, Exh. No. APB-1CT at 4 – 5.

<sup>279</sup> Exh. No. 15C, Response to Bench Request No. 3.

<sup>280</sup> RCW 19.285.040.

<sup>281</sup> Another attribute of electricity generated by renewable facilities is the Production Tax Credit (PTC), which is a federal tax credit awarded to the facility owner for each kilowatt of electricity generated.

renewable generation, using electricity to serve load and either selling or banking the RECs<sup>282</sup>.

195 *Positions of the Parties.* In its initial filing, PacifiCorp stated that during the test year it received \$4,211,639 in revenue from the sale of RECs to other utilities.<sup>283</sup> However, PacifiCorp did not account for any of this revenue in its revenue requirement calculations. PacifiCorp's stated rationale for excluding this revenue was that it intended to "bank" all eligible RECs in the future to help meet jurisdictional-specific renewable portfolio standards.<sup>284</sup> Insofar as Washington is concerned, this rationale depended in significant part on the Company's assertion that it "anticipated legislative changes to Washington's RPS which would allow longer-term REC banking; and therefore would not sell excess RECs in 2011."<sup>285</sup> No such change occurred. Long-term banking of RECs is not allowed under current Washington law.<sup>286</sup>

196 In rebuttal testimony, PacifiCorp at least tacitly acknowledges these circumstances, agreeing with Staff that test year results should be relied on to determine an amount of REC revenue to be reflected in the Company's rates.<sup>287</sup> PacifiCorp proposed on rebuttal to reduce the Washington revenue requirement approximately \$5.0 million, based on REC revenues of approximately \$4.8 million. Staff had proposed reflecting somewhat less, about \$4.2 million, but agreed in its brief with the Company's

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<sup>282</sup> There is no REC organized market in this region. Therefore, sales are generally consummated through bi-lateral negotiations.

<sup>283</sup> Dalley, Exh. No. RBD-1T at 9 – 10.

<sup>284</sup> Dalley, Exh. No. RBD-1T at 9 – 10, Dalley, Exh. No. RBD-3 at 3.5.

<sup>285</sup> Duvall, TR 298.

<sup>286</sup> Public Counsel Initial Post-Hearing Brief ¶ 62.

<sup>287</sup> Duvall, Exh. No. GND-5T at 3.

figure.<sup>288</sup> ICNU's initially proposed adjustment is in line with the amount to which PacifiCorp and Staff agree.<sup>289</sup>

197 Staff also recommends that the Commission order PacifiCorp to record as a regulatory liability all REC revenues from January 1, 2010, forward.<sup>290</sup> Staff recommends that the Commission address the ratemaking treatment of the deferred revenues in future general rate cases.<sup>291</sup>

198 The Company criticizes Staff's proposal to establish a regulatory liability account effective January 1, 2010, and characterizes it as retroactive ratemaking.<sup>292</sup> The Company also objects that such treatment would result in double-counting the REC revenues and violation of the matching principle.<sup>293</sup>

199 *Commission Decision.* The Commission considered the appropriate accounting and rate treatment for RECs for the first time in a proceeding concluded less than one year ago.<sup>294</sup> This proceeding is only the second occasion upon which such issues have been raised for determination in a litigated case.<sup>295</sup> In the prior contested case, the

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<sup>288</sup> Staff Initial Post-Hearing Brief ¶ 24. Some parties refer to this adjustment as an adjustment to "Green Tag" revenues. For the sake of consistency, we use the term renewable energy credit or REC because the parties are referring to the same revenues.

<sup>289</sup> Falkenberg, Exh. No. RJF-1CT at 2. ICNU argues in its Initial Post-Hearing Brief that test year revenues should be increased by \$10 million, but this amount is not adequately supported, if supported at all, by the record in this proceeding.

<sup>290</sup> Foisy, Exh. No. MDF-1T at 10 – 11. Staff would also allow the Company to accumulate interest on the balance at its after-tax rate of return.

<sup>291</sup> Foisy, Exh. No. MDF-1T at 11.

<sup>292</sup> Duvall, Exh. No. GND-5T at 7.

<sup>293</sup> Duvall, Exh. No. GND-5T at 6.

<sup>294</sup> *Washington Utilities and Transportation Commission v. Puget Sound Energy Co.*, Docket UE-070725, Order 03 (May 20, 2010). See also *id.* Order 05 (August 31, 2010) and Order 06 (October 26, 2010).

<sup>295</sup> Issues related to REC revenues were resolved on the basis of the Commission's approval of a "black box" settlement in PacifiCorp's most recent prior general rate proceeding. *Washington Utilities and Transportation Commission v. PacifiCorp.*, Docket UE-090205 (Order 09) (December 16, 2009). Order 09 and the rates that resulted from the Commission approved

Commission determined fundamentally that the REC benefits should go to all of PSE's retail ratepayers because they are the ones burdened with the responsibility of paying rates sufficient for the Company to recover all of the costs of the resources that generate the RECs, including a reasonable return on the Company's investment.

200 Beyond that fundamental determination, to which we adhere in this proceeding, questions concerning the proper accounting and rate treatment for REC proceeds proved challenging in the PSE docket. Indeed, it was not until Commission action on petitions for reconsideration<sup>296</sup> and on a joint proposal by the parties expressly invited by the Commission,<sup>297</sup> that these questions were fully resolved.

201 The Commission finds again in this case that neither the record nor the briefing on legal issues is fully sufficient to make all necessary determinations concerning the amount of RECs that should be returned to customers, various accounting issues, and the precise rate treatment that should be afforded REC proceeds received by PacifiCorp. Accordingly we will make in this Order only fundamental determinations concerning the treatment of REC proceeds. We also will provide some guidance to the parties while requiring further briefing and alternative or agreed proposals concerning certain matters, so that we can fully determine the details of how PacifiCorp will be required to treat REC revenues in terms of account and rates.

202 As previously indicated, we adhere in this proceeding to the basic principles discussed in Order 03 in Docket UE-070725 that require the proceeds derived from the sale of RECs to be returned to customers. In this proceeding, we determine further that these proceedings should be returned in the form of bill credits, identified separately on customers' monthly bills.

203 Since, in our view, questions remain concerning the timing and amounts on which PacifiCorp's REC proceeds should be based for the test, post-test, and rate periods implicated by this case, we will require PacifiCorp to establish a separate tracking

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settlement now are the subject of a formal complaint filed by Public Counsel and ICNU in Docket UE-110070.

<sup>296</sup> *Washington Utilities and Transportation Commission v. Puget Sound Energy Co.*, Docket UE-070725, Order 05 (August 31, 2010).

<sup>297</sup> *Washington Utilities and Transportation Commission v. Puget Sound Energy Co.*, Docket UE-070725, Order 06 (October 26, 2010).

account for all REC proceeds received beginning January 1, 2009 (*i.e.* the beginning of the test year) and continuing through the rate year (*i.e.* until 12 months from the effective date of rates following approval of PacifiCorp's compliance filing in this docket). We also will require PacifiCorp to maintain the tracking account for subsequent periods.

204 In order to initiate the bill credit to customers coincident with the increase in rates they will experience based on our other determinations in this proceeding, we will accept for purposes of establishing 2011 credits the amount of REC revenues to which Staff and PacifiCorp agree, approximately \$4.8 million.<sup>298</sup> This amount will be returned to ratepayers in 12 monthly credits in the same manner in which rate classes are assigned cost responsibility for the generation resources that produce REC revenue.

205 At the end of the rate year, PacifiCorp will be required to submit a full accounting of REC proceeds actually received during the preceding 12 months. This accounting will be considered in light of other information to determine if the amount of credits that should have been returned to customers exceeds or fall short of the estimated \$4.8 million upon which the initial bill credits are based. In other words, the Commission will authorize a true-up of the initial credits that can be reconciled as credits are paid during the following 12 months.

206 At the end of the rate year and each subsequent annual period after the end of the rate year, PacifiCorp will be required to provide an estimate of the REC proceeds its expects to receive during the following 12 months. This is the amount on which credits during that period will be based. As at the conclusion of the initial period there will be a true-up at the end of each subsequent 12 month period. Having stated the basis upon which we resolve the issue for purposes of setting rates and establishing credits in this proceeding, we return to our earlier discussion of the concerns we have with the state of the record on the issue of RECs. In light of our concerns we require, as we did in Docket UE-070725, that the Company prepare and file within 60 days following the date of this Order a detailed accounting of all REC proceeds received during the period January 1, 2009, to the most recent date for which data are available. The report must include any updated forecast of

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<sup>298</sup> It appears from Dalley, Exh. No. RBD-6 at 1.4, that the precise amount is \$4,678,193, though that is not perfectly clear from the exhibit.



PacifiCorp's REC sales for the rate year. We direct the company to work cooperatively with Commission Staff as to the form and content of this filing so that it will prove most beneficial to the Commission.

207 We require this detailed accounting, in part, considering the disputed question of whether PacifiCorp should be required to include, in what we here describe as a tracking account, REC proceeds received during periods after the test year, including those received during the pendency of this proceeding. Staff proposed that REC proceeds received after January 1, 2010, be accounted for and established as a regulatory liability on the Company's books, the rate treatment of which could be determined in a future proceeding. Another possible starting date for such an account might be the date on which PacifiCorp made its initial filing in this proceeding, which put the rate and accounting treatment of REC revenues in issue. Other possible dates are conceivable, including the start of the rate year. We do not finally resolve these questions in this Order. We require additional briefing on the subject, and may require additional evidence. We will establish process and schedule for this by subsequent notice.

208 We also require the Company to file within 60 days after the date of this Order a detailed proposal for operation of the tracking mechanism going forward. This proposal should be developed in consultation with Staff and any other parties who wish to participate. The proposal must include a detailed discussion of the allocation method(s) the Company uses, or proposes to use, when allocating and reporting REC proceeds to Washington. If other parties disagree with PacifiCorp as to the details of the tracking mechanism or the allocation and reporting method(s) PacifiCorp uses or proposes to use, they may file alternative proposals.

### 3. SO<sub>2</sub> Emission Allowance Sales Revenue

209 PacifiCorp's initial testimony includes a 15-year amortization of current and past SO<sub>2</sub> emission allowance sales revenues in its cost of service.<sup>299</sup>

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<sup>299</sup> The Commission ordered the Company to use a 15-year amortization period for revenues associated with the sale of SO<sub>2</sub> emission allowances by Order 01 entered September 14, 1994, in Docket UE-940947.

- 210 Joint Parties propose that the unamortized balance of SO<sub>2</sub> allowance revenues at December 31, 2009, be amortized over five years instead of 15 years.<sup>300</sup> Joint Parties argue that five years is generally the most widely accepted amortization period for extraordinary events or recurring events with volatility.<sup>301</sup> They also assert that a five-year amortization period is more appropriate because it more timely credits customers' rates for the sales of SO<sub>2</sub> allowances.<sup>302</sup>
- 211 In rebuttal, the Company agrees with a five-year amortization period and proposes to increase NOI by \$322,038.<sup>303</sup> The Company adds that the adjustment removes the sales that occur in the test period.<sup>304</sup>
- 212 *Commission Decision.* We accept the Company and Joint Parties' agreement to modify the amortization period established by prior order. The unamortized balance of SO<sub>2</sub> allowance revenues as of December 31, 2009, should be amortized over five years thereby increasing NOI by \$322,038.

#### 4. Temperature Normalization - Retail Sales

- 213 Temperature normalization is a ratemaking method that seeks to project an "average" level of electric sales (kWh) in the rate year by adjusting actual sales in the test year to reflect "normal" temperatures over a longer period of time. This tool, usually called a "temperature normalization adjustment," seeks to average out the rate peaks and valleys that can occur if actual temperatures are either above or below the average. Many customers in PacifiCorp's service territory in Washington use electricity for space heating, which increases their sensitivity to fluctuations in temperature.

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<sup>300</sup> Meyer, Exh. No. GRM-1T at 17.

<sup>301</sup> *Id.* at 18.

<sup>302</sup> *Id.* at 19.

<sup>303</sup> Dalley, Exh. No. RBD-6 at 12.0.

<sup>304</sup> Dalley, Exh. No. RBD-4T at 3.

- 214 *Positions of the Parties.* PacifiCorp includes a temperature normalization restating adjustment that decreases revenues for the residential class by \$5,577,662.<sup>305</sup> In this case, it used the temperature normalization methodology agreed to by the parties in a previous rate case.<sup>306</sup>
- 215 Joint Parties argue that the Company's average actual usage per residential customer over the last five years is higher than the Company's temperature normalized customer usage for the test year.<sup>307</sup> They propose to decrease test year revenues by \$79,439 (after the offset for additional fuel expense) as compared to what they state is PacifiCorp's \$4,337,210 decrease.<sup>308</sup> Joint Parties state that it is proper to use actual data averaged over five years instead of temperature-normalized data to determine per customer use.<sup>309</sup>
- 216 In rebuttal testimony, the Company recommends rejecting the Joint Parties' adjustment pointing to Staff's testimony that the Company's residential class forecast demonstrates a good approximation of the relationship that exists between temperature fluctuations and electricity consumption.<sup>310</sup> The Company argues that the Joint Parties' calculation is faulty because it removes out-of- period adjustments and uses a five-year average without presenting either a rationale or precedent for doing so.<sup>311</sup>
- 217 In cross-answering testimony, Staff also opposes the Joint Parties' adjustment asserting that they should have used temperature-normalized usage, not actual usage,

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<sup>305</sup> Dalley, Exh. No. RBD-3 at 3.1.

<sup>306</sup> See *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket UE-050684, Order 04 (April 17, 2006).

<sup>307</sup> Meyer, Exh. No. GRM-1T at 16.

<sup>308</sup> *Id.* at 16.

<sup>309</sup> *Id.* at 17.

<sup>310</sup> Duvall, Exh. No. GND-5T at 13.

<sup>311</sup> *Id.* at 13.

and that they fail to account for factors that offset the additional revenue they seek to impute to PacifiCorp.<sup>312</sup>

- 218 *Commission Decision.* We determine that the Joint Parties failed to support their recommendation that residential revenues should be based on the last five years of actual usage. The Company's temperature normalization methodology was included in a settlement adopted by the Commission, and that methodology's application to residential customer usage has proven to be quite accurate. We find that temperature normalization is a more appropriate method to estimate test year sales because many of PacifiCorp's customers use electricity for space heating and temperature may have a significant impact on customer usage.
- 219 Staff, moreover, compared usage for the 12-month period ending December 31, 2009, with the usage for the 12-month period ending June 2008. This comparison revealed a two percent increase in actual residential usage between these periods. However, a comparison of the temperature-normalized usage revealed that there was virtually no change in usage.<sup>313</sup> This comparison demonstrates that the increased usage can be solely attributable to differences in temperature. Simply put, the Joint Parties' proposed adjustment creates exactly the situation we seek to avoid: significant fluctuations in rates due to temperature differences.
- 220 Accordingly, we conclude that the Company's residential temperature normalization adjustment reflects an appropriate correlation between temperature fluctuations and residential electrical consumption.<sup>314</sup>

## 5. Temperature Normalization - Commercial Sales

- 221 The second aspect of temperature normalization relates to an adjustment to commercial sales, rather than residential sales.
- 222 *Positions of the Parties.* The Company's temperature normalization adjustment is a restating adjustment that normalizes revenues in the test period by comparing actual

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<sup>312</sup> Schooley, Exh. No. TES-4T at 4.

<sup>313</sup> *Id.* at 5.

<sup>314</sup> Novak, Exh. No. VN-1CT at 8; Staff's Initial Post-Hearing Brief at 5.

sales to temperature-normalized sales using the average weather over a 20-year rolling time period (currently 1990 through 2009).<sup>315</sup> This adjustment combines both residential and commercial sales using the methodology discussed in the previous subsection.<sup>316</sup>

223 While Staff agrees with the Company's methodology, it asserts that its application to commercial class customers produces unreliable results because it fails to explain 35.6 percent of the variation between temperature and commercial loads.<sup>317</sup> Staff's assertion is based on its claim that the Company's analysis does not show a sufficiently proximate relationship between temperature and electricity consumption.<sup>318</sup> Staff proposes removing the Company's temperature normalization adjustment for commercial sales only.

224 PacifiCorp recommends the Commission retain the commercial temperature normalization portion of its adjustment.<sup>319</sup> The Company argues that Staff's analysis should be rejected for three reasons. First, Staff's analysis is too limited because its sole focus is on the sensitivity coefficient or R-square value.<sup>320</sup> Second, the Company's methodology is consistent with Commission practice. Moreover, Staff agreed to this methodology in a previous case and now objects to its application to the commercial class. And finally, the Company's temperature normalization adjustment improves the accuracy of the combined load forecast.<sup>321</sup>

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<sup>315</sup> Dalley, Exh. No. RBD-1T at 8.

<sup>316</sup> Dalley, Exh. No. RBD-3 at 3.0.

<sup>317</sup> Novak, Exh. No. VN-1CT at 9.

<sup>318</sup> *Id.* at 8.

<sup>319</sup> Duvall, Exh. No. GND-5T at 10.

<sup>320</sup> The R square value is the statistical correlation between two variables; in this case, temperature and electricity consumption or load, that seeks to establish a coefficient over a period of ranges. For example, an R-value of .70 means that in 70 percent of cases, over a range of scenarios, the correlation is predictable and in 30 percent of cases it is not predictable.

<sup>321</sup> Duvall, Exh. No. GND-5T at 9 – 10.

225 *Commission Decision.* We agree with Staff that PacifiCorp failed to meet its burden to prove that its temperature normalization adjustment produces a reliable result that should be applied to the commercial class. The Company's adjustment does not demonstrate a proximate relationship between temperature and electricity consumption. Staff suggests that other analyses of the data could be performed to examine the causes of the wide variability in results, including evaluating subgroups within the commercial class.<sup>322</sup> This is an option the Company may wish to pursue in a future rate case. Our rejection of the Company's temperature normalization adjustment for the commercial class reduces revenue requirement by \$965,319.

## 6. Restating and *Pro forma* Wage Increases

226 *Positions of the Parties.* The Company restates its test year wages for increases in labor costs to reflect salary increases for all employees during the test year. This adjustment increases the revenue requirement by \$30,329.<sup>323</sup> PacifiCorp also proposes a *pro forma* wage increase that reflects union contract based wage increases effective after the test year, as of December 2010. This adjustment increases wages by \$392,082. Union labor cost increases were adjusted using contract agreements whereas non-union and exempt employee adjustments are based on actual labor cost increases effective January 2009 and 2010.<sup>324</sup> The Company adjusts payroll taxes to reflect the impact of the changes. However, PacifiCorp did not adjust changes in workforce levels, employee benefits and incentives, or pensions.<sup>325</sup>

227 The Joint Parties oppose both the restating and *pro forma* wage adjustments.<sup>326</sup> With respect to the *pro forma* wage adjustment, they argue it should be disallowed because the Company did not consider all relevant factors including whether there are corresponding offsets to the wage increases such as changes in workforce levels or

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<sup>322</sup> Novak, Exh. No. VN-1CT at 11.

<sup>323</sup> Dalley, Exh. No. RBD-1T at 10.

<sup>324</sup> *Id.* at 10.

<sup>325</sup> Dalley, Exh. No. RBD-1T at 11.

<sup>326</sup> Meyer, Exh. No. GRM-1CT at 21-25, 29.

the Powerdale Hydro Removal adjustment.<sup>327</sup> With respect to the restating adjustment, they argue that 2009 wage increases for officer and exempt employees should be limited to the average increase granted to the other labor groups, or 2.07 percent. This adjustment would reduce required revenues by \$128,366.<sup>328</sup>

228 In rebuttal testimony, PacifiCorp argues that both officer/exempt and non-exempt employees received an actual 3.5 percent wage increase in 2009, rather than the 2.07 percent increase provided to union employees.<sup>329</sup> It contends that it is unreasonable to limit non-union employees' wage increase to that afforded union employees because the negotiated agreements with union employees may have included offsetting benefits that make a direct comparison difficult. PacifiCorp also opposes the Joint Parties' proposal to eliminate the *pro forma* increases in labor costs arguing that these costs are known, measurable, and reasonable because the "Company implemented 2010 wage increases were slightly below market ..." and only for employees earning a base salary below \$100,000.<sup>330</sup> The Company notes that the Joint Parties do not object to the level of the proposed 2010 wage increase, but rather that other adjustments should be included in the revenue requirement. Finally, PacifiCorp stresses that the Joint Parties do not provide evidence supporting the "other adjustments."<sup>331</sup>

229 *Commission Decision.* We reject the Joint Parties' adjustments to 2009 and 2010 wage increases. We are not persuaded by their argument that the wage increase for non-union employees should be limited to the level of wage increase granted union employees. As PacifiCorp and Staff point out, the Joint Parties erroneously assume that all employees have the same overall compensation package thereby allowing a direct comparison of wage levels. Negotiated agreements with union employees may

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<sup>327</sup> *Id.* Meyer does not explain the Powerdale Hydro Removal adjustment, but we believe he is referring to the cost savings realized by the Company's retirement of the Powerdale hydroelectric facility. If so, the cost savings realized by the Powerdale adjustment are already reflected in the Company's filing.

<sup>328</sup> Meyer, Exh. No. GRM-1CT at 29.

<sup>329</sup> Wilson, Exh. No. EDW-3T at 12 - 13.

<sup>330</sup> Wilson, Exh. No. EDW-3T at 15.

<sup>331</sup> Wilson, Exh. No. EDW-3T at 16.

well consider other offsetting benefits such as increased medical benefits and pension or other retirement funding. In any event, there is no argument that the 2009 wages result in above-market compensation. These known and measurable wage increases are reasonable and should be approved.

230 We do not lightly reject the Joint Parties argument that all wage increases in 2010 should be eliminated because workforce reductions can offset any increases.<sup>332</sup> In this difficult economic time, utilities, like other businesses, should find ways to tighten their belts to minimize costs for the benefit of their customers and their investors. PacifiCorp, moreover, largely failed to show it is taking substantial actions to cut costs,<sup>333</sup> and the Company offered no convincing evidence that it is making aggressive efforts to reduce its administrative and general and other variable expenses. However, there are two reasons why, in this case, we cannot make the requested adjustments.

231 First, although it appears that workforce levels are lower, there is insufficient evidence in this record to quantify a potential offset to the revenue requirement. No witness of the Joint Parties offered an adjustment for us to evaluate or for the other parties to critique. Accordingly, we would be creating an adjustment out of an imprecise record on this point, a task we are reluctant in this instance to undertake.

232 Second, even if the proposed adjustment could be precisely quantified, the Joint Parties do not demonstrate that these are permanent work force reductions. The Company persuasively countered that the reduction in workforce levels is temporary and the slight downward trend is due to a hiring lag. PacifiCorp also states that while these positions are available and expected to be filled, many of these positions required specific skills, training, and education levels and the Company must take the time to find employees with appropriate qualifications.<sup>334</sup>

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<sup>332</sup> Dalley, TR 365.

<sup>333</sup> Reiten, TR 231 – 233; Reiten, RPR-1T at 5.

<sup>334</sup> Dalley, TR. 364 - 367. In any event, if we were to embark on our own adjustment based on reduced workforce numbers, the impact on Washington costs would be minimal. At most the record suggests a reduction of 65 employees in the full-time equivalent employees of the Company's system-wide workforce of 5,651. That would translate into approximately nine fewer employees allocated to Washington.



233 With respect to other “offsetting” factors such as the Powerdale Hydro Removal, the Joint Parties fail to demonstrate any relationship between the expiration of the amortization period of this asset and the wage increases. As we noted in other proceedings, a party proposing an offset must net *all* changes in revenues and expenses utility-wide to determine whether a particular adjustment is offset.<sup>335</sup> In this case, the Joint Parties performed no such analysis.

234 Additionally, there is an inaccurate undercurrent in the Joint Parties’ argument that these wage increases somehow benefit the higher echelon of PacifiCorp management. The majority of the employees receiving these wage increases are not executives but are professional, technical, support, and middle-management employees making less than \$100,000 per year.<sup>336</sup>

235 The 2010 *pro forma* wage increases reflect known and measurable changes, and we approve them. We reiterate that the Joint Parties failed to make any argument that the 2010 wage increases elevated employee compensation above market-value.

## 7. Affiliate Management Fees

236 *Positions of the Parties.* PacifiCorp asserts that it was billed for \$8.53 million in MidAmerican Energy Holding Company (MEHC) Washington-allocated management fees during the test year.<sup>337</sup> In its restated actual adjustment, PacifiCorp removes \$1,053,029 leaving a total of \$7.3 million.<sup>338</sup> PacifiCorp contends that \$7.3 million is the maximum allowed under the MEHC Washington acquisition commitment.<sup>339</sup>

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<sup>335</sup> *Washington Utilities & Transportation Commission v. Puget Sound Energy*, Docket Nos. UE-090704/UG-090705, Order 11 (April 2, 2010).

<sup>336</sup> Wilson, Exh. No. EDW-3T at 13.

<sup>337</sup> Dalley, Exh. No. RBD-3 at 4.5. In its supplemental response to Bench Request No. 1, the Company states that it was actually billed \$11.5 million in MEHC fees. The Joint Parties acknowledged that \$11.5 million is the actual billed amount.

<sup>338</sup> Dalley, Exh. No. RBD-1T at 12; Exh. No. RBD-3, at 4.5.

<sup>339</sup> Dalley, Exh. No. RBD-1T at 12.

237 Joint Parties state that PacifiCorp pays an annual Management Fee to MEHC under an “Intercompany Administrative Services Agreement.”<sup>340</sup> According to the Joint Parties, the Agreement allocates certain MEHC costs to its subsidiaries.<sup>341</sup> They recommend disallowance of the following costs under the Management Fee as inappropriate to include in Washington rates:

- MEHC and MidAmerican Energy Company (“MEC”) bonuses,
- costs of the Supplemental Executive Retirement Plan (SERP), and
- legislative costs and contributions.<sup>342</sup>

238 In rebuttal testimony, the Company accepts Joint Parties’ removal of SERP and legislative expenses from the MEHC affiliate management fee on the basis that these costs are inappropriate to include in rates. The Company also removes capitalized expenses, the cost of air travel in excess of commercial-equivalent, and long-term incentive payments.<sup>343</sup> The Company argues that its rebuttal adjustments and the Joint Parties’ adjustments should be applied against the total amount billed by MEHC rather than the \$7.3 million that remains in Washington-allocated expenses after the Company removed amounts above the cap.<sup>344</sup> The combined effect of the Company’s rebuttal adjustments reduces this amount to \$7.11 million. It argues that because the \$7.1 million is less than the level of the Merger Commitment cap of \$7.3 million, no additional adjustment is necessary.<sup>345</sup>

239 *Commission Decision.* We conclude that Joint Parties misconstrue the merger commitment and apply the wrong methodology. Our order establishing the \$7.3 million “cap” simply means that *any* expenses over that level will be deemed unreasonable for Washington ratepayers to bear and will be disallowed. The

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<sup>340</sup> Meyer, Exh. No. GRM-1CT at 33.

<sup>341</sup> *Id.* at 33.

<sup>342</sup> *Id.* at 34.

<sup>343</sup> Dalley, Exh. No. RBD-4T at 5.

<sup>344</sup> *Id.* at 6 – 7.

<sup>345</sup> *Id.* at 7.

Company's proposed management fee is well below the cap. Accordingly, we allow the \$7.11 million in MEHC management fees.<sup>346</sup>

## 8. Annual Incentive Plan (AIP)

240 *Positions of the Parties.* PacifiCorp proposes to include \$1.4 million in incentive compensation expenses arguing that its primary goal in determining employee compensation is to provide pay at the market average.<sup>347</sup> In addition, it contends that to encourage superior performance, a certain percentage of an employee's compensation must be "at risk,"<sup>348</sup> its AIP provides employees with the incentive to perform at an above average level.<sup>349</sup>

241 PacifiCorp asserts that incentive compensation is a greater benefit to customers than compensation consisting solely of base compensation because a higher level of employee performance is achieved and the Company is able to attract and retain talented employees in a competitive market.<sup>350</sup>

242 The Company's AIP provides performance awards based on: (1) the employee's performance against individual goals; (2) the employee's performance against group goals; and (3) success in addressing new issues and opportunities that arise.<sup>351</sup> Individual goals constitute 70 percent of the performance award and group goals account for the remaining 30 percent. PacifiCorp states that employees are not

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<sup>346</sup> That having been said, we are less than enthusiastic about some of the expenses included in the fee. During the hearing, there was considerable discussion about the bonus paid to MEHC's chief executive officer (CEO). It is difficult for us to reconcile the general concept of "bonuses" with the Company's assertion that it is undergoing "belt-tightening" measures to reduce costs. However, the amount of CEO bonus allocated to Washington ratepayers is \$102,000. Stuver, TR. 435 – 36.

<sup>347</sup> Wilson, Exh. No. EDW-1T at 3.

<sup>348</sup> *Id.* at 4.

<sup>349</sup> *Id.* at 5.

<sup>350</sup> *Id.* at 5.

<sup>351</sup> *Id.* at 6.

evaluated on the basis of the financial performance of the Company.<sup>352</sup> PacifiCorp maintains a separate plan for executives that awards bonuses based on corporate performance; that plan is paid for by shareholders, not ratepayers.<sup>353</sup>

243 In this case, the annual cost of the AIP based on the twelve-months ended December 31, 2009, is approximately \$29.8 million on a system-wide basis. It seeks to recover the Washington-allocated share of this expense of \$1.4 million.<sup>354</sup>

244 The Joint Parties recommend that one-half of the incentive compensation expense, or \$700,000, be disallowed.<sup>355</sup> The Joint Parties argue that the goals for the achievement of incentive compensation payments are not well-defined and many of the goals are not quantitative.<sup>356</sup> They state that PacifiCorp's AIP is based on the achievement of six group goals including: (1) customer focus; (2) job knowledge; (3) planning and decision making; (4) productivity; (5) building relationships; and (6) leadership.<sup>357</sup>

245 The Joint Parties assert that an acceptable incentive plan should include goals that improve or maintain PacifiCorp's existing operational performance in areas such as safety, managing operation and maintenance expenses, system reliability, and customer service.<sup>358</sup> They further note that some of the group goals enhance shareholder value, instead of providing tangible benefits to ratepayers.<sup>359</sup>

246 In rebuttal testimony, the Company states that ICNU recommended that the Commission disallow incentive compensation payments in PacifiCorp's last litigated

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<sup>352</sup> *Id.* at 7.

<sup>353</sup> *Id.* at 8.

<sup>354</sup> *Id.* at 8.

<sup>355</sup> Meyer, Exh. No. GRM-1CT at 9.

<sup>356</sup> *Id.* at 9.

<sup>357</sup> *Id.* at 10; Exh. No. GRM-5 at 1 – 2.

<sup>358</sup> Meyer, Exh. No. GRM-1CT at 10 - 11.

<sup>359</sup> *Id.* at 14.

general rate case in 2006.<sup>360</sup> The Commission rejected ICNU's argument that the payments were tied to business and financial performance and concluded that the payments were related to operational effectiveness, customer satisfaction, and safety.<sup>361</sup> The Company asserts that the current structure and goals of the AIP reflect the principles that the Commission stated in its approval of these costs in the 2006 case.

247 PacifiCorp reiterates that adopting the Joint Parties' position will result in employees being under-paid because the incentive compensation is not a "bonus;" it is an integral part of a competitive level of pay.<sup>362</sup> PacifiCorp contends that the Commission has generally left companies with the task of determining appropriate employee incentives and should reject the Joint Parties' proposal to disallow what it calls an arbitrary and unsupported 50 percent reduction to its AIP.

248 *Commission Decision.* As we decided in the last litigated case, we conclude that the 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.

249 There does not appear to be disagreement that this is a preferable means to structure employee compensation. In fact, during the hearing, the Joint Parties agreed that it was preferable to have employee compensation with an incentive component rather than a flat salary.<sup>363</sup>

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<sup>360</sup> Wilson, Exh. No. EDW-3T at 3. PacifiCorp's last litigated general rate case was Docket UE-061546.

<sup>361</sup> *Id.* at 3.

<sup>362</sup> *Id.* at 4.

<sup>363</sup> Meyer, TR 513 -514.

250 We do not wish to delve too deeply in to the Company's management of its human resources and the manner in which it determines overall compensation policy. Thus, we inquire only whether that compensation exceeds the market average, is unreasonable, and offers benefits to ratepayers. No party disputes that the total amount of compensation, adding the base salary and incentive compensation elements, results in a sum equivalent to the market average. The AIP is reasonable and its goals offer benefits to ratepayers. Accordingly, we reject the Joint Parties' proposed adjustment.

### 9. Legal Expenses

251 *Positions of the Parties.* The Joint Parties recommend that \$48,931 be excluded from the Company's outside legal expenses.<sup>364</sup> The Joint Parties argue that, while it may be reasonable to allocate some expenses using an overhead allocation factor; other expenses should be limited to the jurisdiction in which the costs occurred.<sup>365</sup> They contend that legal expenses should not be calculated using the allocation factor and that \$48, 931 in legal expenses be excluded because they were not generated in Washington.

252 PacifiCorp opposes this selective adjustment that departs from the normal method cost allocation set forth in the WCA. The Company notes that Staff also identifies cost categories that are being allocated to Washington customers on a system-wide basis rather by direct assignment.<sup>366</sup> However, rather than potentially increasing the revenue requirement by assigning costs to specific states, Staff proposes that the parties discuss ways to refine the allocation assignment of accounts on an overall basis in accordance with the WCA methodology.

253 *Commission Decision.* We agree with the Company and Staff that this proposal is too selective and should be rejected. We encourage the parties to engage in a dialogue that explores effective means to refine the allocation of *all* cost categories and

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<sup>364</sup> Meyer, Exh. No. GRM-1CT at 24.

<sup>365</sup> *Id.* at 24.

<sup>366</sup> Company Initial Post-Hearing Brief, ¶¶ 132 - 133, *citing* Foisy, Exh. No. MDF-1CT at 16, Dalley, Exh. No. RBD-4T at 21.

quantifies the revenue requirement impact of state-specific cost allocation versus the use of a system allocation factor.

## D. Tax Adjustments

### 1. Repairs Deduction

254 *Positions of the Parties.* PacifiCorp proposes to normalize the cumulative effect of an Internal Revenue Service (IRS) approved change in its income tax accounting for certain capital assets. The change in tax accounting allows the Company to expense a cost for income tax purposes, instead of capitalizing and depreciating it for regulatory purposes.<sup>367</sup>

255 The IRS allowed PacifiCorp to adopt the “repairs deduction” method of accounting starting January 1, 2008.<sup>368</sup> However, it appears that the Company also recognized the “repairs deduction” retroactively for the years 1999 to 2007.<sup>369</sup> With that in mind, the Company also proposes that its adjustment be considered “non-final” in nature and requests that the \$14,463,685 reduction to rate base be “adjusted if necessary after the Service [IRS] has completed its examination ....”<sup>370</sup>

256 Recognizing the impact of the change in its income tax accounting on its regulatory books, the Company recognized a deferred tax to account for the related book-tax timing difference. The timing difference is caused by the rapid recovery afforded by the repairs deduction for tax purposes and the slower depreciation for regulatory purposes. The increase in accumulated deferred taxes using average of monthly averages reduces the Company’s revenue requirement by \$1.7 million.<sup>371</sup>

257 Staff agrees with the adjustment, but asserts that the Company’s recognition of the rate base impact reflects only half of the impact to accumulated deferred income

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<sup>367</sup> Fuller, Exh. No. RF-1T at 2.

<sup>368</sup> *Id.* at 3.

<sup>369</sup> Fuller, Exh. No. RF-3C.

<sup>370</sup> Fuller, Exh. No. RF-1T at 5 – 6.

<sup>371</sup> *Id.* at 5.

tax.<sup>372</sup> Staff proposes a \$28,927,930 deferred tax deduction from rate base thereby decreasing the Company's revenue requirement by \$3.5 million.<sup>373</sup>

258 In rebuttal testimony, PacifiCorp argues that deferred taxes are a source of interest-free funds that can be used to support of rate base investment. However, it contends that a utility cannot use the funds until it realizes the benefit. In this case, the Company argues it did not realize the benefit of the repairs deduction until it filed its income tax return in September 2009.<sup>374</sup> The Company argues that the deferred tax amount was properly recorded in 2009, but Staff improperly characterizes it as a prior year adjustment.<sup>375</sup>

259 *Commission Decision.* The parties do not dispute that PacifiCorp is expensing certain repair costs that it previously capitalized for tax purposes. Because the Company creates a book-tax difference by continuing to capitalize these costs, the parties also agree that the amounts should be normalized. Therefore, the sole issue is the timing of recognition and magnitude of the impact on rate base. The Company contends that it did not receive the benefit of the repairs deduction until it filed its federal income tax return in September 2009, so it reduces rate base by \$14,463,685. Staff, on the other hand, calculates the full impact of the tax accounting change during the entire test year and reduces rate base by \$28,927,370.

260 PacifiCorp argues that the Commission denied an adjustment in the 2009 Puget Sound Energy (PSE) rate case that is identical to the adjustment Staff proposed here.<sup>376</sup> The Company's reliance on that case is misplaced. In the PSE case, we rejected the argument that *no* adjustment could be made to rate base until after an IRS audit because the amount was not known and measurable. Here, according to the Company, the accumulated deferred income tax liability balance as of December 31,

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<sup>372</sup> Breda, Exh. No. KHB-1T at 23.

<sup>373</sup> *Id.* at 13 -14, 23.

<sup>374</sup> Fuller, Exh. No. RF-8T at 12.

<sup>375</sup> *Id.* at 13.

<sup>376</sup> *Washington Utilities & Transportation Commission v. Puget Sound Energy*, Dockets UE-090704/UG-090705, Order 11 at ¶¶ 193 – 197 (April 2, 2010).



2009, is \$28,927,370.<sup>377</sup> Thus, the amount is both known and measurable. In addition, the IRS allowed the tax treatment in the PSE case long after the end of the test year. Here, in sharp contrast, the IRS allowed the tax treatment *during* the test year.<sup>378</sup>

261 We conclude that Staff is correct and we should accept its adjustment to reduce rate base by \$28,927,370, which reflects the impact of the full year of the change. The repairs deduction is an ongoing difference in accounting that will be in effect for the same period as the rates set in this proceeding. The change is known and measurable. Accordingly, it is reasonable to normalize and reflect the impact as if it were in effect for the entire period. The impact of this adjustment reduces the revenue requirement by \$1,822,309 in addition to the \$1.7 million the Company has already recognized.

## 2. Interest Reserve

262 *Positions of the Parties.* The Company requests approval to establish a regulatory asset or liability to recover interest paid to or received from the IRS for any audit adjustments the IRS may make to the repairs deduction taken by the Company in its 2008 and 2009 income tax returns.<sup>379</sup>

263 Staff contends that although there is a risk of an adverse IRS audit, the exact level of risk is unknown. Therefore the Company's request to establish a regulatory asset or liability is premature.<sup>380</sup> Citing a prior Commission order, Staff argues that the Company can request an accounting order once any costs associated with an adverse IRS ruling become known and measurable. Staff asserts that the Commission would then consider the deferred costs in a future rate proceeding.<sup>381</sup>

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<sup>377</sup> Fuller, Exh. No. RF-5 at 1.

<sup>378</sup> In the PSE case, we rejected the proposed adjustment because “[T]he final disposition with the IRS is not known and the tax impact is in any event subsequent to the test year.” Order 11 at ¶ 197.

<sup>379</sup> Fuller, Exh. No. RF-1T at 5.

<sup>380</sup> Breda, Exh. No. KHB-1T at 21 - 22.

<sup>381</sup> *Id.* at 21.

264 *Commission Decision.* We reject the Company’s request to establish an interest reserve account. We agree with Staff that the Company’s request is premature because, at this juncture, the Company does not have a definitive ruling from the IRS. This leaves us with no means to measure any risk the Company faces. PacifiCorp may request an accounting order when the results of any IRS audit are known and measurable.

### 3. Federal Income Tax: Normalization or Flow-Through

265 *Positions of the Parties.* The Company proposes in its originally filed case to adjust its books to reflect full income tax normalization accounting for regulatory rate-setting purposes. It has, with the exception of Allowance For Funds Used During Construction (AFUDC) equity,<sup>382</sup> abandoned the partial flow-through method traditionally used by the Commission.<sup>383</sup> The Company proposes to move to full normalization for practical reasons because income taxes are fully normalized in Oregon, Utah, and Wyoming which constitute 85 percent of the Company’s total regulated operations. It asserts that full normalization would create a clear and unambiguous policy for the Commission and Washington would benefit from increased efficiency in the Company’s income tax accounting and reporting processes.<sup>384</sup>

266 PacifiCorp further argues that “[a]s a policy matter, the Company supports [full] tax normalization based on the matching principle and intergenerational equity.”<sup>385</sup> The Company contends that its proposal matches tax benefits with cost responsibility and prevents customers who pay costs beyond the tax life of an asset from incurring a disproportionately higher tax rate than customers who pay over the life of the same asset.<sup>386</sup>

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<sup>382</sup> AFUDC is the cost of borrowed funds and equity used for construction purposes which is capitalized for later recovery. The deferred equity component is considered a temporary difference for general accounting purposes under *Accounting Standards Code* 980-740-25. The Company, however, proposes continued flow-through treatment of the book-tax difference.

<sup>383</sup> Fuller, Exh. No. RF-1T at 6.

<sup>384</sup> *Id.* at 6.

<sup>385</sup> *Id.* at 6 – 7.

<sup>386</sup> *Id.* at 7.

267 The Company requests approval to account for Washington-allocated income taxes on a fully normalized basis, except for AFUDC-equity, effective January 1, 2011.<sup>387</sup> To fully implement income tax normalization, the Commission would need to address the disposition of an income-tax regulatory asset associated with income tax flow-through.<sup>388</sup> Because the Commission has required the flow-through of tax-book timing differences that were not mandated to be normalized under the Internal Revenue Code, any conversion to full normalization must recognize a regulatory asset. The regulatory asset would represent the deferred tax amount associated with costs for which the rate payer has already received the benefit through a lower income tax expense.<sup>389</sup> However, because the Company is proposing to use flow-through accounting through December 31, 2010, PacifiCorp requests the Commission address the regulatory asset issue associated with its proposed transition to full normalization in its next rate case.<sup>390</sup> The change to full income tax normalization, other than the book-tax difference associated with AFUDC equity, reduces the Company's revenue requirement by \$5,967.<sup>391</sup>

268 Staff recommends the Commission reject the Company's proposal because flow-through accounting passes the tax benefits to customers as the customer receives them.<sup>392</sup> Staff buttresses this position with four arguments. First, PacifiCorp did not fully address the impact of full normalization, so it is unknown since it would be considered in its next rate case. Second, PacifiCorp did not demonstrate the overall impact on ratepayers. Third, adopting full normalization for PacifiCorp could require the Commission to apply the same policy to all companies.<sup>393</sup> Finally, retention of

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<sup>387</sup> *Id.* at 8.

<sup>388</sup> *Id.* at 10.

<sup>389</sup> *Id.* at 10.

<sup>390</sup> *Id.* at 10.

<sup>391</sup> Fuller, Exh. No. RF-8T at 6.

<sup>392</sup> Breda, Exh. No. KHB-1T at 8.

<sup>393</sup> *Id.* at 22 – 23.

partial flow-through accounting is consistent with prior Commission decisions, two of three of which it cites involve PacifiCorp.<sup>394</sup> Staff's adjustment reduces the overall revenue requirement by \$1,174,264.

269 In rebuttal, the Company argues that it did provide support for the impact for full normalization and<sup>395</sup> that it did address customer impact. It refers to a calculation in its direct testimony of the reduction in revenue requirement compared to flow-through accounting.<sup>396</sup> The Company counters Staff's argument that approval of full normalization for PacifiCorp will require application of the same treatment for all companies. Citing the same three cases as Staff, it argues that they are examples of the Commission approving normalization to varying degrees.<sup>397</sup>

270 In addition, the Company argues that it addressed all the issues it needs to address according to standard accounting methods: (1) the timing of the change; (2) whether the change is retrospective or prospective; and (3) the proper treatment of the flow-through effect from past periods.<sup>398</sup> Specifically, the change would take effect in 2011. It would be prospective, and the income tax effect would be reversed over the same time period as flow-through accounting. The Company recommends reversing the remaining book-tax differences over a fixed amortization period that would approximate the current time period to result in no net effect on customers.<sup>399</sup>

271 In support of its proposal, the Company argues that full normalization should not be prescribed prior to allowing temporary book-tax differences in rates.<sup>400</sup> It contends that it is necessary to "freeze and quantify" the flowed-through effects from prior

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<sup>394</sup> *Id.* at 8.

<sup>395</sup> Fuller, Exh. No. RF-8T at 2.

<sup>396</sup> *Id.* at 4.

<sup>397</sup> *Id.* at 4 -5.

<sup>398</sup> *Id.* at 2, citing Robert L. Hane & Gregory Aliff, *Accounting for Public Utilities*, § 1701[5] (2008).

<sup>399</sup> *Id.* at 3.

<sup>400</sup> *Id.* citing Federal Energy Regulatory Commission Order 530.

periods for its book-tax differences for non-fixed assets. Citing a regulatory “Catch 22,” PacifiCorp claims it cannot quantify the flowed-through amount and propose an amortization period without Commission authorization to fully normalize and even then not until the close of the 2010 calendar year.<sup>401</sup>

272 In the alternative, if the Commission finds that additional analysis and discovery is necessary, the Company proposes that the Commission order PacifiCorp to file an accounting application within 30 days from the date of the final order and establish a six-month review period.

273 Finally, if the Commission rejects the Company’s proposal to adopt full normalization, the Company argues that Staff’s adjustment to remove the impact of full normalization from the *pro forma* financials is incorrect for two reasons. First, the Company contends that Staff’s adjustment includes the impact of other state income taxes. Second, it does not exclude all deferred income tax expense and accumulated deferred income taxes for non-property-related book-tax differences that are not required to be normalized.<sup>402</sup> The Company argues that Staff does not remove deferred taxes related to certain book-tax differences that it believes are not consistent with the Commission’s regulatory treatment of income taxes on a flow-through basis.<sup>403</sup> The effect of Staff’s inclusion of the deferred taxes is a \$6.4 million reduction to rate base.<sup>404</sup>

274 In supplemental testimony the Company further explains that the purpose of its adjustment to remove state income taxes is to recognize that although state taxes are considered a system-wide cost, they are not recoverable in Washington.<sup>405</sup> The Company also clarifies its proposal to use full normalization accounting for income taxes rather than the current partial flow-through basis adopted by the Commission.

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<sup>401</sup> Fuller, Exh. No. RF-8T at 4.

<sup>402</sup> *Id.* at 9.

<sup>403</sup> Fuller, Exh. No. RF-14T at 2.

<sup>404</sup> Fuller, Exh. No. RF-15.

<sup>405</sup> Fuller, Exh. No. RF-11T at 1 and 4.

- 275 In supplemental responsive testimony, Staff revises its proposed adjustment and states that, with the new more detailed information provided by the Company in its supplemental filing, it was able to “more accurately portray federal income taxes on a Commission basis.”<sup>406</sup> Staff adjusts the Company’s “per books” income taxes to what it argues is the correct method for ratemaking in Washington; (*e.g.*, partial flow-through accounting).<sup>407</sup> Staff’s revised adjustment results in a \$5.4 million rate base reduction, with a \$323,865 decrease in income tax expense.<sup>408</sup>
- 276 In supplemental rebuttal testimony, the Company argues that the Staff revised adjustment is inconsistent with its opposition to the Company’s full normalization proposal. As evidence, the Company cites the Staff’s use of normalized accounting for book-tax differences not required to be normalized by the Internal Revenue Code as well as the Staff’s normalization of other items not explicitly approved for normalization accounting by the Commission.<sup>409</sup>
- 277 *Commission Decision.* Any decision to allow full normalization is a significant policy decision. We have used flow-through accounting for income taxes generally since liberalized depreciation was first introduced into tax law.<sup>410</sup> Thus, we must carefully evaluate the merits of this proposed policy change and first decide if there is ample evidence in the record to demonstrate that it will not harm ratepayers and not generate unwarranted revenue for the Company.
- 278 We conclude that PacifiCorp failed to meet its burden to prove that we should adopt full normalized accounting for income taxes. The Company explains that it cannot quantify the flowed-through amount and propose an amortization period without our

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<sup>406</sup> Breda, Exh. No. KHB-5T at 1.

<sup>407</sup> *Id.* at 1.

<sup>408</sup> *Id.* at 3.

<sup>409</sup> Fuller, Exh. No, RF-14T at 1.

<sup>410</sup> For example, the Commission states the company should be put on notice that any future use of liberalized depreciation on a normalized basis will be subject to immediate flow through if permissible under the tax law.” *Washington Utilities and Transportation Commission v. Pacific Northwest Bell Company*, Cause No. U-9880, Second Supplemental Order at 15 (November 1969).

approval to fully normalize taxes; a situation it explains as a “regulatory Catch-22.”<sup>411</sup> We view this issue differently. The Company, in essence, is asking us to approve a “black box” whose contents would not be revealed until its next general rate case. That is unsatisfactory because it does not provide us with sufficient information to assess the validity of the request. The Company defies logic by arguing that an accounting-based number remains a mystery until we approve the methodology that generates that number. Accordingly, we reject PacifiCorp’s proposal to convert to full normalized accounting for income taxes and adopt Staff’s recommendation to adjust rate base.<sup>412</sup>

279 Our rejection of full normalization requires an adjustment to rate base. Because the Company’s case is filed on a fully-normalized basis, it is necessary to revise the accumulated deferred income tax (ADIT) amount that is included in rate base. First, we address Staff’s reduction to rate base resulting from removal of \$5.4 million of prepaid income taxes from accumulated deferred income taxes. In support of its adjustment, Staff argues that all non-property items not protected by Internal Revenue Code normalization requirements (or as provided by Commission Order) should be flowed-through.<sup>413</sup> The Company does not contest this adjustment. Given our rejection of full normalization, we adopt Staff’s recommendation to adjust total accumulated deferred income tax to reflect flow-through accounting.

280 Staff proposes a \$6.4 million reduction to rate base related to deferred taxes the Company contends were flowed-through. In its analysis the Company treats the ADIT on these regulatory assets as flow-through and argues we should reject Staff’s proposal, maintaining that the Commission did not explicitly authorize normalization of the tax benefits.<sup>414</sup> The Company contends that absent explicit authorization to normalize, tax benefits must be recognized on a flow-through basis.<sup>415</sup>

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<sup>411</sup> Fuller, Exh. No. RF-8T at 3 - 4.

<sup>412</sup> PacifiCorp asks in the alternative that we order the Company to file an accounting petition and establish a six-month review period. The Company, however, may file an accounting petition on its own initiative and thus does not need a Commission order requiring such a filing.

<sup>413</sup> Breda, Exh. No. KHB-5T at 4.

<sup>414</sup> Fuller, Exh. No. RF-14T at 2.

<sup>415</sup> PacifiCorp Initial Post Hearing Brief at 43.

281 We find the Company's argument lacking. These regulatory assets were deferred by specific Commission decisions. This dispute largely concerns the proper deferred tax treatment for the regulatory asset created by the Chehalis plant. In the Company's last general rate case, we accepted a settlement that established a regulatory asset for the Chehalis plant.<sup>416</sup> According to RCW 80.80.060(6) and WAC 480-100-435, the cost of the investment and related taxes are deferred, which we interpret to be consistent with normalization. Therefore, we accept Staff's recommendation to remove \$6,404,813 in ADIT from rate base.<sup>417</sup>

#### 4. Interest True-Up

282 In this case, all parties calculate the interest true-up adjustment by multiplying the rate base by the weighted cost of debt to determine the *pro forma* interest expense.<sup>418</sup> We approve and adopt this approach for purposes of this case.

#### E. Rate Base Adjustments

##### 1. Working Capital/Jim Bridger Mine O & M/Current Assets

283 Working capital is a component of rate base that consists of cash and other short-term funds that can be used to finance non-utility plant items such as accounts receivables and certain inventories and supplies. It also helps finance the lag between billing and collecting for utility services. The dispute in this case concerns both the selection of a methodology to determine the amount of working capital to include in rate base and how to apply the methodology to a multi-state utility like PacifiCorp.

284 *Positions of the Parties.* The Company calculates working capital using the one-eighth of Operations & Maintenance (O&M) formula,<sup>419</sup> an approach commonly

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<sup>416</sup> *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket UE-090205, Order 09 (December 16, 2009).

<sup>417</sup> The remaining assets, the Grid West loan was deferred in Docket UE-060703 and included as an uncontested adjustment in Docket UE-061546, PacifiCorp's last litigated general rate case. The Powerdale hydro plant and decommissioning costs were deferred in Docket UE-070624.

<sup>418</sup> Foisy, Exh. No. MDF-1CT at 15.



referred to as the “formula method” or the 45-day method. The formula method divides total Washington-allocated normalized O & M expenses, less fuel and purchased power, by eight which is the approximate number of 45-day periods within a year.<sup>420</sup> In effect, this method assumes that a company always has 45 days worth of working capital in hand. This formula is also used by the BPA in the calculation of average system costs for investor-owned utilities.<sup>421</sup> Using the formula method, the Company’s working capital is approximately \$37 million, composed of \$11.2 million in cash working capital, \$11.3 million in current assets (including \$7.8 million in materials and supplies and \$3.5 million in fuel stock); and an additional \$4 million in materials and supplies and fuel stock related to transferring the Jim Bridger Mine to rate base.<sup>422</sup>

285 Staff uses the Investor-Supplied Working Capital (ISWC) method to analyze the average of monthly averages for the test year on the basis of the total company balance sheet.<sup>423</sup> The ISWC method is a balance sheet approach of computing working capital; it is the net difference between current assets and current liabilities. Staff’s approach involves a detailed analysis of the Company’s assets and liabilities to determine the amount of working capital and takes the further step of determining its source. In operation, ISWC limits working capital to the amount provided solely by investors by systematically removing any non-investor provided working capital.<sup>424</sup> Staff proposes to remove all working capital, including the individually identified fuel stock and materials and supplies items, because such working capital is not investor-supplied.<sup>425</sup> The result is working capital of a negative \$7.0 million.<sup>426</sup> Staff

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<sup>419</sup> Dalley, Exh. No. RBD-1T at 21. According to the Company, it used this method in its last two rate proceedings.

<sup>420</sup> *Id.* at 21.

<sup>421</sup> *Id.* at 21.

<sup>422</sup> *Id.* at 21.

<sup>423</sup> Schooley, Exh. No. TES-1T at 14.

<sup>424</sup> *Id.* at 10.

<sup>425</sup> *Id.* at 6.

<sup>426</sup> Schooley, Exh. No. TES-2 at 4.

criticizes the formula method because it assumes that investors supplied the working capital.

286 Staff also opposes the inclusion of the materials and supplies and fuel stock related to the Jim Bridger mine in rate base as working capital. It argues that because the Company has not provided that working capital, it should not be included.<sup>427</sup>

287 The Joint Parties support the use of a lead-lag study to compute working capital though they did not perform such a study for this case. Such a study analyzes who provides the flow of cash necessary to fund day-to-day operations.<sup>428</sup> If a utility must expend cash before the ratepayer pays for utility service, a shareholder provides the cash. However, if the ratepayer pays for service before the utility needs to pay expenses, the ratepayers provides the cash. They argue that a lead-lag study provides an adjustment to rate base allowing a utility to earn a return on the amount of cash necessary for operations that is supported by capital on which investors are entitled to a return.<sup>429</sup> They contend that electric utilities generally have negative working capital when a properly calculated lead-lag study is performed.<sup>430</sup> The Joint Parties criticize the Company's formula method because it assumes that a utility has a 45-day revenue lag and zero expense lag which can only produce a positive working capital amount.<sup>431</sup> Like Staff, the Joint Parties recommend that no working capital be allowed in rate base.<sup>432</sup>

288 In rebuttal, PacifiCorp argues that Staff is using essentially the same allocation methodology that the Commission rejected in its last litigated general rate case.<sup>433</sup> The Company contends that Staff's use of a total company approach in its analysis of

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<sup>427</sup> Schooley, Exh. No. TES-1T at 6.

<sup>428</sup> Meyer, Exh. No. GRM-1CT at 5.

<sup>429</sup> *Id.* at 5.

<sup>430</sup> *Id.* at 4.

<sup>431</sup> *Id.* at 5.

<sup>432</sup> *Id.* at 4.

<sup>433</sup> Dalley, Exh. No. RBD-4T at 18, referencing Docket UE-061456.

working capital fails because it includes significant Company investments not allocated to Washington under the WCA allocation methodology.<sup>434</sup> In addition, it opposes Staff's rate base removal of materials and supplies and fuel stock arguing that those items are necessary to maintain generation, transmission, and distribution functions and provide service to customers.<sup>435</sup>

289 The Company argues that the Joint Parties' proposed adjustment to working capital lacks "any valid basis."<sup>436</sup> The Company notes that Joint Parties do not present a lead-lag study and primarily rely on their witness' experience that lead-lag studies for electric utilities generally show a negative working capital allowance.<sup>437</sup>

290 *Commission Decision.* We considered the issue of working capital in several prior rate cases beginning in 2006 when we rejected the Company's lead-lag study and Staff's ISWC method.<sup>438</sup> In the Company's last litigated general rate case, we also rejected both the Company's and Staff's working capital computations.<sup>439</sup> The issue is now before us again.

291 Of the three methods proposed, we are persuaded that the Staff's methodology is the most appropriate for this case. We agree with Staff that this dispute centers on the choice of the most appropriate methodology for working capital, rather than a disagreement on the actual calculation of the adjustment. Although the Joint Parties recommend the use of the lead-lag methodology, they did not submit any such study in this record and, therefore, we decline to adopt its use here.

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<sup>434</sup> *Id.* at 17.

<sup>435</sup> *Id.* at 16.

<sup>436</sup> Dalley, Exh. No. RBD-4T at 15.

<sup>437</sup> *Id.* at 13.

<sup>438</sup> *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket UE-050684, Order 04 at 66 (April 17, 2006).

<sup>439</sup> *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket UE-061546, Order 08 (June 21, 2007).

292 Regarding the Company's formula method, we agree with the arguments of Staff and the Joint Parties that it is deficient because it assumes that investors provide all funds necessary to the operations of the Company. As a result, we agree that this method will always produce positive working capital.<sup>440</sup> There are instances when the Company relies on non-investor supplied working capital. For example, non-investor working capital results from the lag between the receipt of a vendor bill and actual payment by the Company. Customer deposits are another common source of non-investor supplied working capital. Because the Company's method fails to recognize the different sources of working capital and separately identify the working capital that shareholders provide, we conclude that the formula method, as presented here, is not useful to calculate working capital.

293 On the other hand, Staff's ISWC method determines working capital by comparing the Company's assets to its invested capital while systematically removing non-investor supplied working capital. Staff can then determine to what extent investors have supplied additional capital that should be added to rate base. In other words, if PacifiCorp's invested capital exceeds its investments, the difference results in positive investor-supplied working capital.<sup>441</sup> Staff's analysis concludes that the Company's invested capital does not exceed investments and therefore, investors did not supply enough working capital.

294 The Company criticizes Staff's use of the total company balance sheet to calculate working capital.<sup>442</sup> Staff counters by pointing out that its method uses Washington-specific allocation factors based on the WCA method.<sup>443</sup> We are not persuaded by the Company's criticism of Staff's use of allocation factors it believes to be inconsistent with the WCA methodology. While we would prefer a rate case that presented only Washington-specific costs and revenues, the middle ground we have accepted is the

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<sup>440</sup> Schooley, Exh. No. TES-1T at 22, Meyer, Exh. No. GRM-1CT at 8.

<sup>441</sup> Schooley, Exh. No. TES-1T at 13.

<sup>442</sup> The Company argues that Staff's approach violates the Commission decision in UE-061546 and that working capital must be calculated on a WCA basis. *See* Dalley, Exh. No. RBD-4T at 14.

<sup>443</sup> Schooley, Exh. No. TES-1T at 9. We note that should we accept the Company's recommendation to reject Staff's ISWC methodology and, having rejected the methodologies proposed by the Company and the Joint Parties, the result would be the same – there would be no investor-supplied working capital adjustment to rate base.

WCA methodology used by the parties to allocate costs and revenues to Washington.<sup>444</sup> To determine working capital, both Staff and the Company start by analyzing the balance sheet accounts of the entire company. If positive working capital results from their analysis, then they allocate some portion of it to Washington. We are satisfied that Staff's method is consistent with the WCA's allocation principles and with our treatment of this issue for other multi-jurisdictional utilities.<sup>445</sup>

295 We next consider whether separately identified items such as materials and supplies and fuel stock should be included in rate base. We recognize that including these amounts in rate base allows recovery *of* the investment plus recovery of a return *on* the investment. We conclude that Staff properly excluded these items from rate base. Materials and supplies and fuel stock are consumed or built into permanent plant.<sup>446</sup> Thus, these items are essentially operating expenses or are transformed into permanent plant assets. To allow their recovery as either operating expenses or plant assets and also consider them working capital that should be added to rate base would allow double recovery of these items.<sup>447</sup>

296 In conclusion, we accept Staff's use of the ISWC method and its calculation of zero working capital. We also accept Staff's proposal to remove from rate base the materials and supplies and fuel stock related to the operations of the Jim Bridger Mine.

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<sup>444</sup> When we approved the WCA interjurisdictional cost-allocation method for Washington in Docket UE-060817, we required a five year review of the method, a review due in approximately June 2012. We expect the review to greatly refine the WCA to produce results that more closely represent Washington-only actual costs and revenues.

<sup>445</sup> We recognize that the application of any methodology in a multi-state region is challenging and that no method is perfect. We note the Company expects to complete a lead-lag study sometime in 2012 and we look forward to reviewing it for possible use in Washington the next rate case.

<sup>446</sup> Dalley, TR 355.

<sup>447</sup> Staff's Initial Post-Hearing Brief ¶ 121.

## F. Cost-of-Service Study/Rate Spread/Rate Design

### 1. Cost-of-Service Study

297 Once the Commission establishes the Company's revenue requirement, the Commission must decide how the Company may generate that revenue in the rates it charges its customers. The first step in this process is to evaluate the Company's cost of service study (COSS) which identifies the costs caused by, or otherwise allocated to, each customer class.

298 *Positions of the Parties.* PacifiCorp prepared a functionalized Washington class COSS based on the historic 12-month period ended December 31, 2009, using the Company's annual results of operation.<sup>448</sup> The 2009 study modifies the previous methodology by revising the peak credit method which is used to classify production and transmission costs as either demand or energy.<sup>449</sup> The peak credit method formerly compared the cost of a current peaking resource, a Simple Cycle Combustion Turbine (SCCT), with the cost of a current baseload resource, Combined Cycle Combustion Turbine (CCCT), to determine the demand-related component.<sup>450</sup> All other costs are specified as energy related. In this case, PacifiCorp uses the capacity costs from its Firm Capacity Sales Agreement (Agreement) with BPA instead of its SCCT costs to determine the demand-related cost component.<sup>451</sup> The Company points out that it modified the peaking resource because it does not employ SCCT generating facilities in the West Control Area.<sup>452</sup> Thus, the new costs reflect actual Company operations within the West Control Area.<sup>453</sup> This modification results in 33 percent of costs being classified as demand-related and 67 percent of costs being classified as energy-relate. This increases the costs allocated to the

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<sup>448</sup> Paice, Exh. No. CCP-1T at 1 - 2.

<sup>449</sup> *Id.* at 2.

<sup>450</sup> *Id.* at 2- 3.

<sup>451</sup> *Id.* at 3. The cost of the BPA Agreement is \$86.43/KW per year.

<sup>452</sup> *Id.* at 5.

<sup>453</sup> *Id.* at 5.

Residential Schedule and decreases the costs allocated to the industrial schedules.<sup>454</sup> Staff does not oppose the Company's use of the BPA Agreement as its peaking resource cost input.<sup>455</sup>

299 ICNU supports the Company's modification to its peak resource input asserting that it takes into consideration the actual peaking resource relied on by PacifiCorp in the West Control Area.<sup>456</sup> However, it disagrees with the use of 100 winter hours and 100 summer hours for allocating system demand-related costs arguing that this factor encompasses too many hours to accurately assign system demand costs.<sup>457</sup> ICNU contends that the peak demand factor should be determined using only those hours that are within 95 percent of the system peak hour or 48 summer hours and 23 winter hours.<sup>458</sup>

300 In rebuttal testimony, the Company opposes ICNU's proposal to calculate peak demand using only those hours that are within 95 percent of the system peak hour because it can produce volatility in results depending on the test period.<sup>459</sup> For example, PacifiCorp notes that had this method been in place during its last rate case then only 35 hours would have been included and none of those hours included the winter peak.<sup>460</sup> PacifiCorp recommends that we reject ICNU's adjustment because it is contrary to the principles of consistency and gradualism as it has the potential to create rate volatility and shift costs between customer classes. It further argues that ICNU's proposal is not based on analytical analysis and that it uses total system peak hours and not just the West Control Area to determine its results.<sup>461</sup>

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<sup>454</sup> *Id.* at 5-6.

<sup>455</sup> Schooley, TES-1T at 30.

<sup>456</sup> Schoenbeck, Exh. No. DWS-1T at 2.

<sup>457</sup> *Id.* at 2 - 3.

<sup>458</sup> *Id.* at 3.

<sup>459</sup> Paice, Exh. No. CCP-6T at 3.

<sup>460</sup> *Id.* at 3 - 4.

<sup>461</sup> *Id.* at 4.

- 301 In cross-answering testimony, Staff agrees that the cost of meeting peak demand should be shared by those using the system at that time but disagrees with ICNU that peak demand should be calculated using only 71 hours or 0.8 percent of the year.<sup>462</sup> Staff argues that it is more reasonable to calculate peak demand using 200 peak hours and note that this time period was specifically approved by the Commission in a previous PSE case.<sup>463</sup> Staff concludes that adopting ICNU's recommendation will further shift costs to residential customers from industrial customers.<sup>464</sup>
- 302 In summary, the sole area of dispute regarding the Company's COSS is the method used to calculate peak demand. ICNU seeks to narrow the peak demand calculation to those hours that fall within 95 percent of the system peak, instead of using the Company's proposed 200 peak hours. The Company and Staff disagree with ICNU's approach and assumptions.
- 303 *Commission Decision.* We accept the Company's unopposed revision to its COSS to replace a SCCT with the costs of its BPA contract. This revision synchronizes the calculation of demand-related and energy-related costs with the Company's actual operations. While we recognize that this modification results in more costs being allocated to residential customers, the change better represents actual system use by the affected classes. We believe this is a sufficient reason to make the change.
- 304 As to the issue in dispute, we reject ICNU's proposal to recalculate the COSS' peak demand calculation. ICNU's calculation would calculate peak COSS from only 71 hours annually, or approximately one-third of the hours considered by PacifiCorp. As we have in the past when presented with a precise revision to peak demand, we conclude that this is too narrow a range.<sup>465</sup> We agree with PacifiCorp that ICNU's

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<sup>462</sup> Schooley, Exh. No. TES-4T at 7.

<sup>463</sup> *Id. citing, Washington Utilities and Transportation Commission v. Puget Sound Energy, Inc.*, Docket Nos. UE-920433/UG-920499/UE-921262, 9<sup>th</sup> Supplemental Order at 11 (August 17, 1993).

<sup>464</sup> Schooley, Exh. No. TES-4T at 8 - 9.

<sup>465</sup> *Washington Utilities & Transportation Commission v. Puget Sound Energy*, Docket Nos. UE-920433/UG-920499/UE-921262, 9<sup>th</sup> Supplemental Order at 12 (August 17, 1993). In that case, the Washington Industrial Committee for Fair Utility Rates (WICFUR) also proposed the use of only those hours within 95 percent of the system peak.



proposal could produce volatility in results depending on the test period.<sup>466</sup> While it is reasonable to allocate the costs of peaking resources based on the hours those resources will actually be used to serve load, the allocation method should be flexible enough to incorporate the variable peaks experienced in Washington. PacifiCorp experiences both a summer peak and a winter peak, and its proposal to include 100 summer hours and 100 winter hours to determine peak demand recognizes how resources are used. The Company points out that had ICNU's proposed methodology been in place during PacifiCorp's last rate case, only 35 hours would have been used to determine peak demand and none of those hours would have included the winter peak.<sup>467</sup> This example clearly demonstrates that ICNU's proposed methodology produces unreasonable results and should be rejected.

## 2. Rate Spread

305 Having allocated its costs among customer classes, PacifiCorp must assign recovery of those costs to each class. Each class generally should be responsible for the costs it causes, but public policy goals and other factors influence the extent to which the rates charged a particular class recover all of the costs allocated to that class. The Commission reviews this rate spread to ensure that it is fair, just, and reasonable.

306 *Positions of the Parties.* In its initial filing, PacifiCorp proposed to spread the rate increase to all rate schedules, other than street lighting, on an equal percentage basis.<sup>468</sup> For street lighting customers, the COSS results suggest only a small increase; the Company proposes a five percent increase for this schedule.<sup>469</sup>

307 Staff proposes higher than average increases in revenue for Residential Service (Schedule 16), Industrial Service (Schedule 48T), and Large General Service (Large General Service >1,000kW) schedules and lower than average increases for the commercial schedules, Small General Service (Schedule 24), Large General Service

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<sup>466</sup> Paice, Exh. No. CCP-6T at 3.

<sup>467</sup> *Id.* at 3 -4.

<sup>468</sup> Griffith, Exh. No. WRG-1T at 2.

<sup>469</sup> *Id.* at 3.

<1,000 kW (Schedule 36), and Agricultural Pumping Service (Schedule 40).<sup>470</sup> Staff proposes a minimal increase for the Street Lighting Service schedules.<sup>471</sup>

308 Using its recommended 10.58 percent overall revenue increase, Staff recommends a 12.5 percent increase for Residential, Large General Service >1,000 kW, and Dedicated Facilities, or 114 percent of the average increase.<sup>472</sup> For Small General Service, Large General Service <1,000 kW, and Agricultural Pumping Schedule, Staff recommends a 9.08 percent increase, or 83 percent of the average increase.<sup>473</sup> For the Street Lighting schedules, Staff recommends a one percent increase or about nine percent of the average increase.<sup>474</sup> Staff argues that its rate spread moves each schedule closer to full parity.<sup>475</sup>

309 ICNU supports the Company's rate spread proposal.<sup>476</sup> ICNU argues that while PacifiCorp overstated the cost of serving the industrial customers on Schedule 48T, it believes the Company's proposed equal percentage rate increase is reasonable.<sup>477</sup> ICNU contends that the Company's COSS demonstrates that all major customer classes are within 96 to 107 percent of parity.<sup>478</sup> It argues that the Company's proposal is consistent with the Commission's practice of approving equal percentage rate increases for classes with similar parity ratios and that it should be approved.<sup>479</sup>

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<sup>470</sup> Schooley, Exh. No. TES-1T at 3.

<sup>471</sup> *Id.* at 3.

<sup>472</sup> *Id.* at 31

<sup>473</sup> *Id.* at 31.

<sup>474</sup> *Id.* at 31.

<sup>475</sup> *Id.* at 35.

<sup>476</sup> Schoenbeck, Exh. No. DWS-1T at 6.

<sup>477</sup> *Id.* at 2.

<sup>478</sup> *Id.* at 6.

<sup>479</sup> *Id.* at 6.

- 310 Wal-Mart argues that the Company's rate spread proposal would move only one customer class closer to the actual cost of service and would create a larger gap between the actual cost of service and other customer classes.<sup>480</sup> Wal-Mart recommends that the Commission approve the Company's proposed rate increases for Partial Requirements Service and Street Lighting services and that the rate increases for Small General Service, Large General Service, and Agricultural Pumping be set at the jurisdictional average.<sup>481</sup> Wal-Mart proposes that the difference be collected from the rate schedules where rates are set at less than the cost of service.<sup>482</sup>
- 311 In rebuttal testimony, wherein the Company reduces its rate increase request from 21 percent to 17.85 percent, it Company concurs with Staff's rate spread recommendation proposing to spread the 17.85 percent rate increase consistent with Staff's recommendation.<sup>483</sup> The Company argues that this approach better reflects cost-of-service study results and applies smaller rate increases to Schedules 24, 36, and 40, and the lighting schedules that are currently paying more than the cost of service.<sup>484</sup> The other major rate schedules would receive a uniform percentage increase. Residential Service (Schedule 16) and Large General Service (Schedule 48T) would receive a 20.2 percent increase, equal to 113 percent of the average increase.<sup>485</sup> The commercial schedules, Small General Service (Schedule 24), Large General Service (Schedule 36), and Agricultural Pumping Service (Schedule 40) would receive a 14.7 percent increase, equal to 83 percent of the average increase.<sup>486</sup> The lighting schedules would receive a one percent rate increase.

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<sup>480</sup> Chriss, Exh. No. SWC-1T at 6.

<sup>481</sup> *Id.* at 6.

<sup>482</sup> *Id.* at 6.

<sup>483</sup> Griffith, Exh. No. WRG-7T at 2.

<sup>484</sup> *Id.* at 2.

<sup>485</sup> *Id.* at 2.

<sup>486</sup> *Id.* at 2.

- 312 In cross-answering testimony, Staff disagrees with ICNU that a 90 to 110 percent parity ratio is reasonable.<sup>487</sup> Staff argues that PacifiCorp's rate schedules have not moved closer to parity over the past five general rate cases.<sup>488</sup> Staff contends that industrial customers on Schedule 48T have been consistently below parity and commercial customers remain at parity ratios great than 1.0.<sup>489</sup> Staff reiterates that its recommendation will move customers toward parity.<sup>490</sup>
- 313 In its cross-answering testimony, ICNU argues that Staff's proposal is inconsistent with Commission decisions about rate spread for many years and should not be adopted.<sup>491</sup> ICNU points out that most major customer classes are within a few points of cost-based rates except for the street lighting class which is well above the class cost assignment.<sup>492</sup> ICNU supports the Company's proposal to assign a modest increase to street lighting and assign an equal percentage increase to other customer classes because they are relatively close to parity.<sup>493</sup> ICNU notes that Wal-Mart's approach is relatively close to the Company's proposal, but ICNU recommends that it be rejected for the same reasons Staff's proposal should be rejected.<sup>494</sup>
- 314 *Commission Decision.* In this case, the parties and all the customers testifying during our public comment hearing addressed the challenges presented by the difficult economic times faced not only by the state of Washington, but by the entire country. While it is true that each party used economic challenges to support a particular position on a specific issue, the concern with current economic conditions was pervasive.

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<sup>487</sup> Schooley, Exh. No. TES-4T at 10.

<sup>488</sup> *Id.* at 11.

<sup>489</sup> *Id.* at 11.

<sup>490</sup> Schooley, Exh. No. TES-4T at 12 -13.

<sup>491</sup> Schoenbeck, Exh. No. DWS-3T at 1.

<sup>492</sup> *Id.* at 3.

<sup>493</sup> *Id.* at 3.

<sup>494</sup> *Id.* at 4.

- 315 This concern reminds us that determining an appropriate rate spread requires consideration of a number of factors and is not the result of pure arithmetic calculations. Of course we consider the results of a valid COSS with the goal of ensuring that each customer class bears the burden of the costs it imposes on the utility. However we also consider principles of rate stability, gradualism, and the avoidance of rate shock.
- 316 Staff's rate spread, now supported by the Company, proposes higher than average increases for certain schedules and lower than average increases for others with the intent to move each customer class closer to full parity. For example, Staff's rate spread would result in residential and industrial customers receiving a rate increase of 114 percent of the average increase. We conclude that this is unreasonable and ignores the other principles that guide a determination of rate spread. Using PacifiCorp's COSS, all major customer classes are within 97 to 107 percent of parity. We conclude that the principles of gradualism and rate stability do not warrant moving these customer classes even closer to actual parity in the current economic conditions. Indeed, the composite effect of the revision to the Company's peak credit method, the proposed rate spread, and the revisions to rate design (which are discussed next) could well result in rate shock.
- 317 These principles of overall fairness, gradualism, and rate stability warrant spreading the rate increase in accordance with the Company's initial proposal: spreading the rate increase to all rate schedules other than street lighting, on an equal percentage basis. For street lighting customers, the Company's initial proposed five percent increase is reasonable.

### 3. Rate Design

- 318 Rate design is the final component of providing the Company with the opportunity to recover its authorized revenue requirement. Rate design determines how the Company structures the rates for each customer class.
- 319 *Positions of the Parties.* The Company asserts that its rate design proposals are consistent with the COSS and are sufficient to recover the proposed revenue requirement.<sup>495</sup> According to the COSS, the costs related to energy charges have

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<sup>495</sup> Griffith, Exh. No. WRG-1T at 3.

increased more than the costs related to other rate components.<sup>496</sup> Therefore, the Company proposes larger increases to energy charges than demand charges.<sup>497</sup>

320 For General Service and Large General Service schedules, PacifiCorp asserts that the COSS indicates that larger increases are needed for energy charges than for demand, load size, and basic charges.<sup>498</sup> The rates for these schedules reflect the COSS results.<sup>499</sup> With respect to Agricultural Pumping Service, the COSS indicates that both the load size and energy charges should be increased.<sup>500</sup>

321 With respect to Street Lighting Schedules, the COSS indicates that only a small increase is warranted, so the Company proposes a five percent increase spread equally to all Street Lighting Schedules.<sup>501</sup> PacifiCorp proposes that the metal halide offering currently available in Schedule 52 be eliminated because the Company has no customers on these rates and does not anticipate any in the future.<sup>502</sup> Moreover, the Energy Independence and Security Act of 2007, Section 324 provides that metal halide fixtures cannot be manufactured after January 1, 2009.<sup>503</sup>

322 Staff recommends that the Commission accept PacifiCorp's proposed increases to basic charges and demand charges for non-residential schedules.<sup>504</sup> Staff asserts that most of the increase is to the energy charge.<sup>505</sup> Staff recommends that the basic charge and demand charges for Schedules 24, 26, and 48T be increased by the amount

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<sup>496</sup> *Id.* at 3.

<sup>497</sup> *Id.* at 3.

<sup>498</sup> *Id.* at 5.

<sup>499</sup> *Id.* at 5.

<sup>500</sup> *Id.* at 5.

<sup>501</sup> *Id.* at 5.

<sup>502</sup> *Id.* at 5 - 6.

<sup>503</sup> *Id.* at 6.

<sup>504</sup> Schooley, Exh. No. TES-1T at 36.

<sup>505</sup> *Id.* at 37.

proposed by the Company regardless of the revenue increase.<sup>506</sup> If the revenue requirement approved by the Commission is less than requested, then Staff recommends that the energy charge be reduced by a commensurate amount.<sup>507</sup>

323 ICNU does not support the Company's rate design for Schedule 48T and argues against increasing energy charges by a greater percentage than demand charges.<sup>508</sup> It contends that to do so would move Schedule 48T further from the cost-of-service. To avoid this result, it recommends that all Schedule 48T charges be increased by the same percentage regardless of the actual revenue increase granted by the Commission.<sup>509</sup>

324 Wal-Mart states that the Company's proposal to increase energy charges which shifts demand cost responsibility from lower load factor customers to higher load factor customers.<sup>510</sup> That is, the Company will over-recover demand cost from higher load factor customers and under-recover demand costs from lower load factor customers.<sup>511</sup> Wal-Mart argues that one benefit of collecting demand-related costs through demand charges is to reduce the risk of revenue instability as customers become more energy efficient, which makes demand-based revenues theoretically more stable than energy-based revenues.<sup>512</sup> Wal-Mart recommends that the Commission approve demand charges for Large General Service that represent 25 percent of the difference between the proposed rate design percentage of 16.7 percent and the proposed cost of service percentage of 29.3 percent, or approximately 20 percent of the total revenue requirement.<sup>513</sup>

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<sup>506</sup> *Id.* at 37.

<sup>507</sup> *Id.* at 37.

<sup>508</sup> Schoenbeck, Exh. No. DWS-1T at 7. In fact, ICNU posits that the rate design should reflect the converse.

<sup>509</sup> *Id.* at 8.

<sup>510</sup> Chriss, Exh. No. SWC-1T at 7.

<sup>511</sup> *Id.* at 8 -9.

<sup>512</sup> *Id.* at 10.

<sup>513</sup> *Id.* at 10.

- 325 In response to ICNU's and Wal-Mart's concerns, the Company revises its rate design for Large General Service, Small General Service, and Industrial Service by increasing all billing elements by a uniform percentage.<sup>514</sup> For Agricultural Pumping Service, PacifiCorp proposes to reflect the revised revenue requirement by increasing the Load Size Charge and Energy Charge by an approximately equal percentage. PacifiCorp proposes an increase of one percent for all street lighting schedules.
- 326 With respect to residential rate design, the Company proposes increasing the monthly residential basic charge from \$6 to \$9 to more closely reflect the COSS results which reflect a cost of \$10.38.<sup>515</sup> PacifiCorp argues that increasing the basic charge to \$9 moves closer to the cost-of-service while minimizing the bill impact.<sup>516</sup> The Company further argues that a \$9 basic charge would continue to be one of the lowest among Washington utilities.<sup>517</sup> For energy charges, PacifiCorp proposes to retain the current inverted rate structure and apply an approximately uniform percentage increase to the two kilowatt-hour blocks.<sup>518</sup>
- 327 Staff recommends that the residential basic charge be increased from \$6.00 to \$7.50 and that the Commission accept the Company's rate design proposal for the other rate schedules.<sup>519</sup> Staff argues that because its proposed revenue increase of 10.58 percent is roughly half of the Company's proposed increase of 20.88 percent; the basic charge should be increased by one-half of the Company's increase or \$1.50.<sup>520</sup> Staff notes that increasing the basic charge effectively reduces the energy charge.<sup>521</sup> Thus, the

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<sup>514</sup> Griffith, Exh. No. WRG-7T at 5.

<sup>515</sup> Griffith, Exh. No. WRG-1T at 4. The \$10.38 figure would cover the Company's costs relating to meters, service drops, meter reading, and billing. *Id.* It is not designed to cover all fixed costs of the Company.

<sup>516</sup> *Id.* at 4.

<sup>517</sup> *Id.* at 4 – 5.

<sup>518</sup> *Id.* at 4.

<sup>519</sup> Schooley, Exh. No. TES-1T at 37.

<sup>520</sup> *Id.* at 37.

<sup>521</sup> *Id.* at 38.



rate impact of a basic charge increase affects a customer with low energy use more than a customer with high energy use.<sup>522</sup>

328 With respect to the Company's proposed increase in the residential basic charge, The Energy Project argues that factors other than the cost of service should be considered when determining the level of the charge.<sup>523</sup> First, The Energy Project contends that when consumption-based costs are diminished and transferred to fixed charges, customers lose the incentive to use energy efficiently.<sup>524</sup> Second, the higher fixed costs disproportionately impact low-use customers many of whom will be low-income customers.<sup>525</sup> The Energy Project recommends that the Commission reject any increase to the residential basic charge.<sup>526</sup>

329 In cross-answering testimony, Staff argues that, contrary to The Energy Project's assertions, energy charges exceeding nine cents per kWh give customers ample opportunity to conserve.<sup>527</sup>

330 In rebuttal testimony, the Company proposes to reduce its proposed increase to the residential basic charge to \$8.50 from its originally proposed \$9.00, and to retain the existing inverted rate structure.<sup>528</sup> The revised residential basic charge reflects the reduced revenue requirement sought in rebuttal. The Company disagrees with The Energy Project that increasing the basic charge sends an anti-conservation message. PacifiCorp argues that its rate structure supports an 18 percent increase in the energy charge and that this rate structure sends a proper conservation signal.<sup>529</sup>

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<sup>522</sup> *Id.* at 38.

<sup>523</sup> Eberdt, Exh. No. CME-1T at 13.

<sup>524</sup> *Id.* at 13.

<sup>525</sup> *Id.* at 14.

<sup>526</sup> *Id.* at 16 – 17.

<sup>527</sup> Schooley, Exh. No. TES-4T at 15.

<sup>528</sup> Griffith, Exh. No. WRG-7T at 3.

<sup>529</sup> *Id.* at 3.

- 331 *Commission Decision.* First, we accept PacifiCorp’s revised rate design proposal for Small General Service, Large General Service, Industrial Service, and Agricultural Pumping Service. We conclude that this rate design adequately addresses the concerns raised by ICNU and Wal-Mart. We further conclude that the Company should be permitted to eliminate the metal halide offering currently available to Street Lighting customers in Schedule 52. As the Company notes, it does not have any customers taking service under Schedule 52 and does not envision any in the future.
- 332 Second, with respect to the residential basic charge, we conclude that the basic charge should remain at \$6.00. While we acknowledge the Company’s and Staff’s intention to bring the basic charge more in line with their proposed rates for the class and to cover a number of the costs attributable to individual customers (such as those associated with meters, service drops, and billing), these are not the only considerations.
- 333 No one questions that we are still in the midst of difficult economic times. Under these circumstances in particular, many customers will view any basic charge increase as an additional increase above and beyond the rates approved in this Order. Those customers will not take into account the offsetting decrease in energy charges that would accompany an increase in their basic charge. Given the significant increase in rates approved in this Order, we do not want to wish to add to the rate burden already imposed on customers, whether real or perceived.<sup>530</sup> Not recovering some of the “basic” costs through the basic charge does not mean those costs will not be recovered; rather, those costs will just be recovered through the variable charges.
- 334 Finally, we share the Energy Project’s concern that lower energy charges could result in reduced deployment of energy efficiency. While no party presented empirical evidence tying a reduced energy charge to the performance of the Company’s energy efficiency program, there is sufficient testimony to establish a logical relationship between lower energy charges and customer interest in energy efficiency. As energy charges decrease relative to increased basic charges, a customer’s energy efficiency investment recovery period is extended, which may negatively affect a customer’s decision to invest in energy efficiency efforts.

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<sup>530</sup> A number of the comments submitted by ratepayers expressed concern about both the overall increase and the increase to the fixed charge. Exh. No. 8.

335 In conclusion, we find no compelling reason to increase the basic charge, and  
therefore, we will retain the current basic charge of \$6.00.

#### 4. Low Income Bill Assistance/Low Income Weatherization Assistance

336 *Positions of the Parties.* The Low Income Bill Assistance Program (LIBA) Program  
credit is available to low-income customers through Schedule 17 and is funded  
through a Schedule 91 surcharge.<sup>531</sup> The Company proposes changes to LIBA that  
will increase the funding level, expand eligibility criteria, and reduce administrative  
overhead.<sup>532</sup> PacifiCorp proposes to increase the Schedule 91 surcharge collections  
by the same percentage amount as the price change proposed for residential customers  
in this case.<sup>533</sup>

337 The Company also proposes to allocate 70 percent of the surcharge to increase the  
low income bill credit and 30 percent to increase the qualifying low income customer  
program cap.<sup>534</sup> PacifiCorp also proposes that income eligibility should be increased  
from 125 percent to 150 percent of the Federal Poverty Level (FPL) to provide a  
benefit to households with a limited income that do not qualify for other services.<sup>535</sup>

338 In addition, PacifiCorp proposes to require bi-annual, rather than annual,  
recertification of eligibility arguing that bi-annual recertification will decrease  
program costs and provide greater benefits to eligible customers.<sup>536</sup>

339 Staff accepts the Company's proposals regarding LIBA, but Staff recommends that  
the Schedule 91 Surcharge be set at 21 percent even if the percentage increase  
approved by the Commission for the residential class is less than that amount.<sup>537</sup>

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<sup>531</sup> Griffith, Exh. No. WRG-1T at 6.

<sup>532</sup> Reiten, Exh. No. RPR-1T at 6.

<sup>533</sup> Griffith, Exh. No. WRG-1T at 6, Exh. No. WRG 2 at 19.

<sup>534</sup> Griffith, Exh. No. WRG-1T at 7.

<sup>535</sup> *Id.* at 7.

<sup>536</sup> *Id.* at 7.

340 The Energy Project proposes to increase LIBA funding in an amount greater than the level of rate increase granted PacifiCorp for its residential customers.<sup>538</sup> It also expresses concern with splitting the incremental increase in LIBA benefits between deepening the existing discount and serving additional customers because the program needs to provide a meaningful benefit to each participating household.<sup>539</sup>

341 With respect to the Company's proposal to modify the program's income eligibility threshold, The Energy Project points out that such a result could reduce the level of benefits for households at the bottom of the poverty ladder.<sup>540</sup> It further notes that last year Washington elected to retain LIHEAP<sup>541</sup> eligibility at 125 percent of the FPL rather than increasing it because of the number of households at the 125 percent level that could not get served.<sup>542</sup> Moreover, The Energy Project argues that having a different eligibility standard for LIBA and LIHEAP funding sets up a double standard that is difficult to explain.<sup>543</sup> In the alternative, it suggests that all parties work toward developing an alternative delivery mechanism before the next rate case.<sup>544</sup>

342 With respect to modifying the certification process to every other year, The Energy Project applauds PacifiCorp's intent to serve more customers, but argues that the proposal hinders agencies' ability to provide income certification because it effectively reduces administrative support.<sup>545</sup> This "feast or famine" approach makes it impractical for agencies to process approximately 5,000 households one year and

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<sup>537</sup> Schooley, Exh. No. TES-1T at 40.

<sup>538</sup> Eberdt, Exh. No. CME-1T at 4.

<sup>539</sup> *Id.* at 4.

<sup>540</sup> *Id.* at 8.

<sup>541</sup> LIHEAP is the federal Low Income Home Energy Assistance Program. *Id.* at 5 and 8.

<sup>542</sup> *Id.* at 8.

<sup>543</sup> *Id.* at 8.

<sup>544</sup> *Id.* at 8 - 9.

<sup>545</sup> *Id.* at 9.

few or none the next.<sup>546</sup> In addition, The Energy Project asserts that the fee PacifiCorp currently pays agencies for certification does not cover the costs of certification and recommends that the certification fee be increased to \$65 per household.<sup>547</sup>

343 Finally, The Energy Project argues that this is a critical time for PacifiCorp to increase its investment in the Low-Income Weatherization Assistance program (LIWA).<sup>548</sup> It notes that The American Recovery and Reinvestment Act (ARRA) added \$59 million to Washington's normal Department of Energy Weatherization Assistance Program (WAP) from 2009 - 2011 argues that PacifiCorp should increase LIWA funding by \$500,000 to fill the void that will be left when ARRA funding expires.<sup>549</sup>

344 In rebuttal testimony, the Company supports Staff's proposal to increase the Schedule 91 surcharge by 21 percent regardless of the actual amount of residential increase approved by the Commission, citing the benefit that this result would confer upon low-income customers.<sup>550</sup>

345 The Company also accepts The Energy Project's proposal to retain the income guideline at 125 percent of FPL noting that revision could increase administrative costs if the income guideline is different than the one used for LIHEAP.<sup>551</sup>

346 PacifiCorp disagrees with The Energy Project's proposal to use all LIBA funds to increase the discount without increasing the cap on the number of program participants.<sup>552</sup> It also opposes The Energy Project's proposal to continue annual

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<sup>546</sup> *Id.* at 11.

<sup>547</sup> *Id.* at 10.

<sup>548</sup> *Id.* at 14.

<sup>549</sup> *Id.* at 14 -16.

<sup>550</sup> Eberle, Exh. No. RME-1T at 3.

<sup>551</sup> *Id.* at 5.

<sup>552</sup> *Id.* at 5.

certification of program participants.<sup>553</sup> During the past program year, agency administrative costs accounted for 21 percent of total program costs and participants' discount accounted for 79 percent.<sup>554</sup> The Company argued that if administrative costs can be decreased, more households will receive program benefits.<sup>555</sup>

347 The Company also opposes The Energy Project's recommendation to increase the administrative fee from \$48 to \$65 per household certified because it does not believe the increase is in the best interest of its customers.<sup>556</sup> However, it recommends that the Commission Staff convene a collaborative meeting with the parties to determine how the certification process can be modified to lower agency costs and increase benefits to people in need.<sup>557</sup>

348 PacifiCorp opposes The Energy Project's proposal to increase LIWA program funding by 50 percent, or approximately \$500,000.<sup>558</sup> The Company budgets \$1 million annually for reimbursements to its partnering agencies, but the agencies do not bill PacifiCorp for the full budgeted amount.<sup>559</sup> In recent years, reimbursements include \$617,263 in 2007, \$532,700 in 2008, \$491,986 in 2009, and \$346,523 through September 2010.<sup>560</sup>

349 In cross-answering testimony, Staff recognizes The Energy Project's concern with biannual certification by suggesting that agencies recertify one-half of the participants for two years and one-half for one year.<sup>561</sup> Staff contends that this compromise would

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<sup>553</sup> *Id.* at 6.

<sup>554</sup> *Id.* at 6.

<sup>555</sup> *Id.* at 6.

<sup>556</sup> *Id.* at 7.

<sup>557</sup> *Id.* at 7.

<sup>558</sup> *Id.* at 8.

<sup>559</sup> *Id.* at 8.

<sup>560</sup> *Id.* at 8.

<sup>561</sup> Schooley, Exh. No. TES-4T at 17.

spread workload over two years and avoid the administrative problems The Energy Project identifies.<sup>562</sup>

350 Staff is not opposed to the principle that PacifiCorp fairly compensate agencies for administering the program but argues that The Energy Project's support for increasing administrative reimbursement is insufficient.<sup>563</sup> Staff notes that The Energy Project only provided information for one agency for one month, so Staff supports retaining the reimbursement rate of \$48 per certified customer.

351 Staff opposes The Energy Project's proposal to increase LIWA funding by \$500,000.<sup>564</sup> Staff argues that the applicable tariff sheet is not before the Commission, that the Commission should conduct a comprehensive review before modifying the benefit charge, and that it was understood that ARRA funding was temporary.<sup>565</sup>

352 In cross-answering testimony, The Energy Project objects to Staff's characterization of LIBA as a "tax" because helping customers living at the economic margin of society provides system-wide benefits in the form of enhanced cash flow, reduction in bad debt expenses, and reduced collection costs.<sup>566</sup>

353 In cross-answering testimony, Staff concurs with PacifiCorp's proposals program eligibility and certification. The Energy Project also reiterates its concerns with those modifications to the program.<sup>567</sup>

354 *Commission Decision.* Overall, we accept the undisputed recommendations regarding the LIBA program. We agree that the Schedule 17 surcharge should be increased by 21 percent to serve more customers and to greater offset the revenue increase

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<sup>562</sup> *Id.* at 17.

<sup>563</sup> *Id.* at 17.

<sup>564</sup> *Id.* at 19.

<sup>565</sup> *Id.* at 19.

<sup>566</sup> Eberdt, Exh. No. CME-5T at 4.

<sup>567</sup> *Id.* at 7 – 9.

approved by this Order. We also retain income eligibility at 125 percent of the FPL because we are concerned that different eligibility levels for LIHEAP and LIBA could create confusion and increase administrative costs.

355 With respect to the proposed modification to LIWA funding, we reject The Energy Project's proposal to increase funding by 50 percent, or an additional \$500,000. The evidence clearly demonstrates that reimbursements under this program have not come close to reaching the current budgeted amount. We encourage The Energy Project, PacifiCorp, or any other party to come forward with such a request if it can demonstrate that a funding increase is necessary to ensure immediate success of the program. Until that time, we will not increase funding.

356 With respect to the disputed issues concerning the allocation of LIBA surcharge collections, the interval for eligibility certification, and the level of administrative fees, we are not convinced that these are appropriate matters for resolution by the Commission through the adjudicative process. These matters should be addressed through negotiations and contracts between PacifiCorp, The Energy Project, and the agencies that actually administer the program, Blue Mountain Action Council, Opportunities Industrialization Center of Washington, and Northwest Community Action Center (collectively referred to as the "agencies"). These entities share the same goals with respect to LIBA and are interested in serving the customers eligible for the program in a manner that maximizes the benefits of the program and fairly compensates the agencies for administering the program.

357 We are also disinclined to address these matters in this proceeding because the adjudicative process, by its very nature, promotes disagreement and relies upon advocacy to fully flesh out issues in dispute. As a result, the hearing room does not advance the discussion necessary to resolve the policy questions raised by the parties. We believe these issues would be more effectively addressed through a collaborative process that includes PacifiCorp, The Energy Project, Staff, and the agencies.

358 Accordingly, we decline to modify the current allocation of the LIBA surcharge collections, the interval for eligibility certification, and the level of administrative fees. Instead, we require PacifiCorp to meet with The Energy Project, Staff, and the agencies to discuss these issues. We recognize the importance of these issues and do not want them to languish, so we require Staff to report to us the results of the collaborative process within six months of the date of this Order.



**FINDINGS OF FACT**

359 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:

- 360 (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 gas  
and electrical companies.
- 361 (2) PacifiCorp provides electric utility service to customers in Washington.
- 362 (3) The rates proposed by tariff revisions filed by PacifiCorp on May 4, 2010, and  
suspended by prior Commission order, are not just, fair or reasonable.
- 363 (4) PacifiCorp's existing rates for electric service provided in Washington State  
are insufficient to yield reasonable compensation for the service rendered.
- 364 (5) PacifiCorp requires relief with respect to the rates it charges for electric  
service provided in Washington State.
- 365 (6) The rates, terms, and conditions of service that result from this Order, based on  
a revenue deficiency of approximately \$38 million are fair, just, reasonable,  
and sufficient.<sup>568</sup>
- 366 (7) The rates, terms, and conditions of service that result from this Order are  
neither unduly preferential nor discriminatory.

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<sup>568</sup> See Appendix A.

- 367 (8) PacifiCorp has met its obligations under the following commitment made at the time MEHC acquired the Company: Commitment 37 – Long-term Debt Yield Reduction. Commitment 37 is complete.

### **CONCLUSIONS OF LAW**

368 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:

- 369 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.
- 370 (2) PacifiCorp is a “public service company” and an “electrical company” as those terms are defined in RCW 80.04.010 and as those terms 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.
- 371 (3) The rates proposed by tariff revisions filed by PacifiCorp on May 4, 2010, and suspended by prior Commission order, were not shown to be fair, just or reasonable and should be rejected.
- 372 (4) PacifiCorp’s existing rates for electric service provided in Washington are insufficient to yield reasonable compensation for the service rendered and should be adjusted to provide the Company a reasonable opportunity to recover its full revenue requirement.
- 373 (5) PacifiCorp should have the opportunity to earn an overall rate of return of 7.81 percent based on the capital structure and costs of capital set forth in the body of this Order, including a return on equity of 9.8 percent on an equity share of 49.1 percent.
- 374 (6) PacifiCorp should be authorized and required to make a compliance filing reflecting rates for electric service that will recover a revenue deficiency of approximately \$38 million and that otherwise satisfies the requirements of this

Order. PacifiCorp and Staff are required to determine the precise amount of the Company's revenue requirement, which may vary slightly from the stated amount due to computational refinements during review of the compliance filing.

- 375 (7) PacifiCorp should be authorized and required to make a compliance filing reflecting net power costs with the adjustments approved in this Order. PacifiCorp and Staff are required to determine the precise amount of net power costs during review of the compliance filing.
- 376 (8) PacifiCorp's compliance filing should include tariff sheets that increase the Schedule 91 surcharge by 21 percent to increase funding of the Company's low income billing assistance program.
- 377 (9) PacifiCorp's compliance filing should include a separate tariff item for Renewable Energy Credits to be reflected on residential customers' monthly bills.
- 378 (10) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient.
- 379 (11) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory.
- 380 (12) 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.
- 381 (13) 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:

- 382 (1) The proposed tariff revisions PacifiCorp d/b/a Pacific Power & Light Co. filed on May 4, 2010, and suspended by prior Commission order, are rejected.
- 383 (2) PacifiCorp is authorized and required to make a compliance filing including such new and revised tariff sheets as are necessary to implement the requirements of this Order. The stated effective date of the revised tariff sheets must allow Staff a reasonable opportunity to review the compliance filing and to inform the Commission whether Staff finds the revised tariff sheets fully conform to the requirements of this Order.
- 384 (3) PacifiCorp must file within sixty days of this Order a detailed accounting of Renewable Energy Credit (REC) revenues received since January 1, 2009, and a detailed proposal for the REC tracking mechanism as required in Section II.C.2 of this Order. These filings, as well as additional filings required to be made in connection with the REC tracker, as discussed in the body of this Order, must be made in this docket as compliance filings or reports, as required under WAC 480-07-880(1) and (3).
- 385 (4) 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 Order.
- 386 (5) Commitment 37 – Long-term Debt Yield Reduction, made at the time MEHC acquired PacifiCorp is deemed to have been fulfilled and the Commitment is complete.
- 387 (6) PacifiCorp must meet with The Energy Project, Staff, and the affected agencies in a collaborative process to discuss the current allocation of the LIBA surcharge collections, the interval for eligibility certification, and the level of administrative fees. Staff must report the results of this process within six months of the date of this Order.

- 388 (7) The Commission retains jurisdiction over the subject matters and parties to this proceeding to effectuate the terms of this Order.

DATED at Olympia, Washington, and effective March 25, 2011.

WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

JEFFREY D. GOLTZ, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, 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 DETERMINATION OF REVENUE REQUIREMENT**

				APPENDIX A		
				COMMISSION DETERMINATION OF REVENUE REQUIREMENT		
				COMMISSION		
LN NO				NOI Impact	Net Rate Base Impact	Commission's Revenue Requirement Impact
	A	B	C	D	E	F
1	Per Books	Adj No.		\$46,232,662	\$751,399,887	\$20,087,225
2	Adjustments					
3	REVENUE					
4	Temperature Normalization	3.1	U	(\$4,357,889)	\$0	\$7,030,214
5	Revenue Normalizing Adjs.	3.2	U	(69,998)	2,751,332	\$459,568
6	Effective Price Change	3.3	U	8,061,401	0	(\$13,004,777)
7	SO2 Allowances	3.4-12.1	C	332,038	(2,334,188)	(\$829,738)
8	Green Tag Revenues	3.5-12.5	C	(2,737,565)	0	\$4,416,282
9	Wheeling Revenue Adjustment	3.6	U	60,438	0	(\$97,500)
10	Remove Commercial Sales	3.7	C	598,382	0	(\$965,319)
12	O & M					
13	Misc. General Expense	4.1	U	28,780	0	(46,428)
14	General Wage Increase-Annualization	4.2	U	(18,800)	0	30,328
15	Proforma General Wage Incr	4.3	U	(243,032)	0	392,063
16	Pension Curtailment	4.4	U	474,858	0	(766,048)
17	Affiliate Management Fee	4.5-12.3	C	59,810	0	(96,486)
18	DMS Removal Adjustment	4.6	U	3,198,895	472,406	(5,100,987)
19	Removal Non-Recurring Entries	4.7	U	127,808	0	(206,182)
20	Remove MEHC Severance	4.8	U	397,117	(306,376)	(679,236)
21	SERP Expense	12.2	C	110,289	0	(177,920)
22	Advertising Expense	12.4	C	1,178	0	(1,900)
23	Combined Cycle O&M Adj	4.9	U	0	0	0
25	POWER					
26	Net Power Costs-Restating	5.1	U	7,150,053	0	(11,534,576)
27	Net Power Costs-Proforma	5.2-12.6	C	(22,135,735)	0	35,709,710
28	Electric Lake settlement	5.3	U	(98,983)	(212,583)	132,897
29	BPA Residential Exchange	5.4	U	(5,216,329)	0	8,415,063
30	James River Royalty Offset	5.5	U	766,070	0	(1,235,836)
31	Removal of Colstrip #3	5.6	U	274,987	(8,160,130)	(1,471,725)
33	DEPRECIATION/AMORTIZATION					
34	Hydro Decommissioning	6.1	U	0	(264,083)	(33,272)
36	TAX ADJUSTMENTS					
37	Interest True Up	7.1-12.9	C	(1,229,228)	0	1,983,010
38	Accum. Deferred Income Tax Factor Cor	7.2	U	0	(5,199,035)	(655,037)
39	Renewable Energy Tax Credit	7.3	U	5,638,736	0	(9,096,496)
40	Mailin Midpoint Adjustment	7.4	U	291,667	(510,417)	(534,830)
41	WA-FAS 109 Flow-Through	7.5	U	(5,532,834)	0	8,925,653
42	AFUDC - Equity	7.6	U	75,955	0	(122,532)
43	Public Utility Tax Adjustment	7.7	U	257,639	0	(415,627)
44	Remove Def State Tax Expense	7.8	U	2,199,228	1,099,614	(3,409,286)
45	Current Year Def Inc Tax Normalization	7.9	C	323,865	(5,401,575)	(1,203,020)
46	Medical Deferred Tax Expense	7.10	U	(170,464)	0	274,995
47	Avg Bal for Accum Def Inc Tax-Property	7.11	U	0	(9,873,199)	(1,243,945)
48	WA Low Income Tax Credit	7.12	U	20,962	0	(33,816)
50	RATE BASE					
51	Cash Working Capital	8.1-12.8	C	0	0	0
52	Jim Bridger Mine Rate Base	8.2	C	0	30,678,372	3,865,233
53	Environmental Remediation	8.3	U	(37,050)	261,509	92,718
54	Customer Advances for Const	8.4	U	0	23,143	2,916
55	Miscellaneous Rate Base	8.5	U	0	(7,864,275)	(990,837)
56	Cont Miscellaneous Rate Base	8.5.1	U	13,847	1,697,440	191,526
57	Removal of Colstrip #4 AFUDC	8.6	U	17,991	(441,006)	(84,587)
58	Powerdale Hydro Removal	8.7	U	109,264	462,824	(117,954)
59	Trojan Unrecovered Plant Adj	8.8	U	99,958	748,258	(66,979)
60	Customer Service Deposits	8.9	U	(22,103)	(2,980,496)	(339,862)
61	Chehalis Reg Asset- WA	8.10	U	(1,861,470)	9,488,085	4,198,376
62	Repairs Deduction	8.11	C	0	(14,463,670)	(1,822,309)
63	Current Assets	8.12	C	0	(11,300,254)	(1,423,743)
65	PRODUCTION FACTOR					
66	Production Factor Adjustment	9.1-12.7	U	50,606	(729,160)	(173,507)
67	(Cont) Production Factor Adjustment	9.1.1-12.7.1	C	136,616	(46,772)	(226,284)
68	Combined Cycle O&M Adj	4.9	U	0	0	0
70				\$33,379,620	\$728,995,651	\$37,999,196

71					
72	CONVERSION FACTOR				0.61988
73					
74	RATE OF RETURN CALCULATION	% OF CAPITAL	COST	WEIGHTED	
75				COST	
76					
77	EQUITY	49.10	9.80		4.81
78	LONG-TERM DEBT	50.60	5.89		2.98
79	SHORT TERM DEBT	0.00	0.00		0.00
80	PREFERRED	0.30	5.41		0.02
81					
82	TOTAL	100.00			
83	WEIGHTED AVERAGE COST OF CAPITAL				7.81%
84					
85				PROFORMA INTEREST	
86				ADJUSTMENT	
87					
88	RATE BASE		\$728,995,651		
89	WEIGHTED COST OF DEBT		0.0298		
90	PROFORMA INTEREST		21,724,070		
91	ACTUAL INTEREST		25,236,151		
92	INCREASE (DECREASE) INTEREST EXPENSE		(3,512,081)		
93	FEDERAL INCOME TAX		1,229,228		
94	NET OPERATING INCOME		(1,229,228)		
95					
96					
97				GROSS REVENUE	
98				REQUIREMENT	
99				INCREASE	
100					
101	PROFORMA RATE BASE		\$728,995,651		
102	AUTHORIZED RATE OF RETURN		7.81%		
103	NET OPERATING INCOME REQUIREMENT		\$56,934,560		
104	PROFORMA NET OPERATING INCOME		\$33,379,620		
105					
106	RECOMMEDED INCREASE (DECREASE)		\$23,554,941		
107	CONVERSION FACTOR		0.61988		
108	INCREASED REVENUE REQUIREMENT		\$37,999,194		



**GLOSSARY**

TERM	DESCRIPTION
AIP	Annual Incentive Plan.
CAEW	Control Area Energy – West. An allocation factor used in the WCA interjurisdictional cost allocation methodology. The CAEW factor is a 100 percent energy weighting of Oregon, Washington and California retail loads based on each states’ share of the west control area temperature normalized annual megawatt hours. .
DC Current Intertie	Direct Current Intertie
Deferral Account	An accounting convention that allows a utility, with authorization from the Commission, to record costs during one period for possible recovery in rates during a subsequent period. Permission to defer costs does not carry a guarantee that the costs will later be allowed in rates or that unamortized deferral balance will be allowed to earn a return as rate base.
GRID	Generation and Regulation Initiatives Decision model. A computer model that PacifiCorp uses to estimate future power costs.
ICNU (Industrial Customers of Northwest Utilities)	Industrial Customers of Northwest Utilities is a regional organization whose members are large industrial customers of various utilities, including PacifiCorp.
ISCW	Investor-supplied working capital. The average amount of capital provided by investors in the company, over and above the investments in plant and other specifically identified rate base items, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The accounting definition of working capital is current assets less current liabilities. According to Goodman, the accounting definition is seldom used in rate regulation. <sup>569</sup>
LIBA	Low income bill assistance. This is a ratepayer-funded program to provide financial assistance to qualified PacifiCorp customers who have difficulty paying their utility bills.
LIWA	Low Income Weatherization Assistance program.

<sup>569</sup> Goodman, Leonard Saul, The Process of Ratemaking, Vol. 2, pp. 828-838 (Public Utilities Reports, Inc., 1998).

MEHC	MidAmerican Energy Holding Company. A part of the Berkshire Hathaway group of companies, MEHC purchased PacifiCorp in 2005 in a transaction the Commission examined and approved in Docket UE-051090
NOI	Net operating income. A company's operating income after operating expenses are deducted, but before income taxes and interest are deducted.
REC	Renewable Energy Credit.
ROE (return on equity)	The rate of earnings realized by a utility on its shareholders' assets, calculated by dividing the earnings available for dividends by the equity portion of the rate base. The Commission establishes an authorized rate of return for recovery in rates.
SCL	Seattle City Light
SERP	Supplemental Executive Retirement Plan.
SMUD	Sacramento Municipal Utility District.
WCA (West control area) allocation	An interjurisdictional cost allocation methodology that eliminates all resources and loads in PacifiCorp's east control area, though it does include resources that serve but are not physically located in the WCA states (Washington, Oregon, California).