BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORATION COMMISSION Complainant, vs. PACIFICORP d.b.a. PACIFIC POWER, Respondent.	**DOCKET UE-100749**

PACIFICORP'S INITIAL POST-HEARING BRIEF

February 11, 2011

TABLE OF CONTENTS

CASES

STATUTES

RULES

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION ORDERS

OTHER ORDERS

I. INTRODUCTION

1. PacifiCorp d/b/a Pacific Power (or the Company) respectfully requests that the Washington Utilities and Transportation Commission (Commission) grant the Company's request for a revenue increase of approximately $47.7 million, or 17.6%[1] on an overall basis, effective April 3, 2011.[2] This compares to the Company's initial filing of $56.7 million, reflecting adjustments in the Company's rebuttal filing[3] reducing the requested revenue increase by $8.2 million, and in the Company's response to Bench Request 3,[4] further reducing the requested increase by approximately $750,000.

2. There are three key factors underlying the revenue increase requested in this case. First, net power costs (NPC) in the Company's West Control Area (WCA) have increased, driven primarily by the expiration of several below-market legacy contracts.[5] NPC in this case reflect replacement of these low-cost contracts at current market prices.[6] Second, while the case does not include major resource additions, it reflects significant infrastructure investments necessary to maintain system safety and reliability.[7] Third, the revenue requirement increase in this case reflects under-recovery of costs in the 2009 historic period.[8] Revenues in the base period include a pro forma adjustment that reflects the rate increase from the Company's last rate case. However, even with this adjustment, the Company's revenues are insufficient to cover its test period costs.[9] The Company's request to increase its return on equity (ROE) from 10.2% to

---

[1] This increase is net of the approximate impact of the net power cost reductions reflected in Bench Request 3.
[2] Dalley Exh. No. RBD-4T 1:12-13; *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Order 1 ¶ 11, Docket UE 100749 (May 12, 2010).
[3] Dalley, Exh. No. RBD-4T 1:13-14.
[4] Bench Request, Exh. No. 16C.
[5] Reiten, Exh. No. RPR-1T 3:11-14.
[6] Reiten, Exh. No. RPR-1T 3:17-20.
[7] Reiten, Exh. No. RPR-1T 4:3-5.
[8] Reiten, Exh. No. RPR-1T 4:14.
[9] As such, no pro forma adjustment to the costs in this case has been made. Dalley, TR. 374:9-375:16.

10.6% comprises approximately $2.5 million of the proposed increase;[10] in contrast, NPC have increased by $13.5 million from the 2009 rate case filing.[11]

3. PacifiCorp has the lowest average retail rates of investor-owned utilities in Washington and its rates are among the lowest in the country.[12] PacifiCorp has worked to keep rates low in the face of cost pressures and the difficult economic conditions existing since 2008. The Company's efforts are reflected in the fact that the Company's costs for operations and maintenance and administrative and general have decreased from the Company's prior rate case.[13] The Company also reduced its 2010 wage increase to below-market levels and limited it to employees who received base compensation below $100,000.[14]

4. The Company's proposed rate increase is far lower than it could have been. The Company deliberately limited its pro forma adjustments to the test period.[15] The Company did not include any pro forma adjustments for capital additions.[16] As such, rates from this proceeding will not include any capital additions in 2010 and 2011.[17] The Company's filing also reflects 2009 historic levels of incentives, employee benefits and pension expenses, and only known and measurable wage increases that occurred prior to the filing.[18] No party has questioned that the Company significantly underearned in the test year. The Company's rebuttal case demonstrates that it earned an ROE of 3.15% for the test period.[19] Staff's Revenue Requirements Summary shows that, including all of Staff's adjustments (many of which the Company contests as set forth below), the Company earned a rate of return of 5.04% during the

[10] Dalley, Exh. No. RBD-6 2.2:68.
[11] Reiten, Exh. No. RPR-1T 9-11 (as adjusted for rebuttal filing and Bench Request 3).
[12] Griffith, Exh. No. WRG-18 1.
[13] Reiten, Exh. No. RPR-1T 5:3-12.
[14] Wilson, Exh. No. EDW-3T 15:16-22.
[15] Reiten, Exh. No. RPR-1T 5:13-17; Dalley, Exh. No. RBD-1T 3:21-23.
[16] Reiten, Exh. No. RPR-1T 6:4-5; Dalley, Exh. No. RBD-1T 4:20-21.
[17] No party has challenged the capital investments included in this filing.
[18] Reiten, Exh. No. RPR-1T 6:5-8.
[19] Dalley, Exh. No. RBD-6T 1.0; Reiten, Exh. No. RPR-2T 2:7-9.

test period, reflecting an implied ROE of 4.22%.[20]

II. LEGAL STANDARDS

5. In setting rates in a general rate case, the Commission determines whether the rates proposed by the utility are fair, just, reasonable, and sufficient.[21] To be considered just and reasonable, rates must include both compensation necessary to provide safe and reliable electric service[22] and "a rate of return sufficient to maintain its financial integrity, attract capital on reasonable terms, receive a return comparable to other enterprises of corresponding risk,"[23] and maintain the utility's creditworthiness.[24]

6. The Supreme Court of Washington found that it is equally important that rates be sufficient to provide safe and reliable service and allow a reasonable opportunity to earn a rate of return to the utility as it is that rates are just and reasonable from the customer's perspective:

> It is just as important in the eye of the law that the rates shall yield reasonable compensation as it is that they shall be just and reasonable and nondiscriminatory from the standpoint of the customer, because unless every rate does yield reasonable compensation, public service companies must resort to discrimination in order to live or must eventually be forced out of business. Every statutory element must be recognized in the fixing of rates or the result will be to defeat the legislative purpose.[25]

7. The court also explained that the effect of the Commission disallowing a prudently incurred operating expense is to reduce the actual rate of return of the utility.[26] Disallowing expenses therefore "has the very real effect, among others, of increasing the risks of investing in the

---

[20] Foisy, Exh. MDF-8 (implied ROE of 4.22%); Foisy, Exh. MDF-2 1 (rate of return of 5.04%)..
[21] RCW 80.28.020.
[22] RCW 80.28.010.
[23] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket Nos. UE-991606, *et al.*, Third Supp. Order at ¶ 324 (2000); *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at ¶ 235 (Apr. 17, 2006).
[24] *See Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
[25] *Wash. ex rel. Puget Sound Power & Light Co. v. Dept. of Pub. Works of Wash.*, 179 Wash. 461, 466 (1934).
[26] *People's Org. for Wash. Energy Res. v. Wash. Utils. & Transp. Comm'n*, 104 Wn.2d 798, 810-11 (1985) (en banc).

utility"[27] and denying the utility a reasonable opportunity to earn a fair rate of return as mandated under the *Hope* and *Bluefield* precedents.[28]

III. COST OF EQUITY AND CAPITAL STRUCTURE

8. The Company presented the following cost of capital recommendations:

Component	Percent of Total	% Cost	Weighted Average
Long Term Debt	47.6%	5.89%	2.80%
Preferred Stock	0.3%	5.41%	0.02%
Common Stock Equity	52.1%	10.60%	5.52%
Total	100.0%		8.54%

The disputed issues are cost of equity and whether the Commission should adopt the Company's actual capital structure or impute a hypothetical capital structure that reduces common equity and includes short-term debt.

A. Cost of Equity

9. Parties challenged the Company's proposed ROE of 10.60%. Staff and the Industrial Customers of Northwest Utilities (ICNU) both recommend an ROE of 9.50%. The Commission should adopt the Company's proposed ROE because, as set forth in the testimony of Dr. Samuel C. Hadaway, it reflects the realities and challenges of the current economy and market conditions and results in just and reasonable rates. Consistent with the general policy of this Commission, Dr. Hadaway's recommendation relies primarily on the results of his discounted case flow (DCF) analysis, using a range of different models and growth rates.

1. Key ROE Indicators Are Similar to Those Prevailing When the Company's ROE Was Last Litigated, Except that Utility Stock Prices and Performance are Much Worse.

10. The Commission approved a 10.2% ROE in the Company's rate case in which ROE was

---

[27] *Id.* at 11.
[28] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692 (1923).

litigated in April 2006 (2005 GRC).[29] When determining a reasonable ROE, the Commission looks to what has changed since the last time it determined a company's ROE.[30] There has been significant market turmoil since the Company's 2005 GRC, and while interest rates and average allowed ROEs are similar, utility stock prices and total returns on an investment in utility common stocks are considerably lower. It is undisputed that utility stock prices and returns are an important consideration in determining ROE.[31]

11. Current interest rates are comparable to those prevailing at the time of the Company's last rate case. At hearing, the most recently available monthly public utility single "A" interest rate was 5.56%.[32] In PacifiCorp's 2005 GRC, the single "A" interest rate used by Mr. Gorman for his risk premium analysis was 5.57% (based on average rates between July-October 2005) —a difference of only *one basis point*.[33]

12. The average ROEs awarded in 2006 are nearly the same as the average ROEs awarded in 2010—10.36% for electric utilities in 2006 and 10.34% in 2010—a difference of *two basis points*.[34] While the use of average ROEs from other jurisdictions is not dispositive, the Commission has noted that it is useful as a measure of reasonableness.[35]

13. In contrast, utility stock prices and performance have declined dramatically since April 2006 when the Commission set a 10.2% ROE for PacifiCorp. Mr. Gorman's testimony demonstrated that in 2006, utility stock indices reflected a return in excess of 20%.[36] As of the second quarter of 2010, however, the utility stock index had a *negative* return of approximately

---

[29] *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at¶ 3 (Apr. 17, 2006).
[30] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-060266, Order 08 at ¶¶ 84-86 (Jan. 5, 2007).
[31] Gorman, TR. 440:7-13.
[32] Elgin, Exh. No. KLE-3 1.
[33] Gorman, TR. 446:12-20; Gorman, Exh. No. MPG-24 15; Elgin Exh. No. KLE-1T 7:16-17.
[34] Gorman, TR. 448:11-17; Elgin, Exh. No. KLE-7 2; Gorman, Exh. No. MPG-24 13.
[35] *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at ¶ 263 (Apr. 17, 2006) ("such comparative data serve as a useful reference on the reasonableness of results from financial analyses applied to a particular company").
[36] Gorman, Exh. No. MPG-1T 7:Fig. 1.

8%.[37] While utility stock indices were outperforming the market in 2006, they are currently underperforming the market.[38] In addition to historic performance data, Standard & Poor's (S&P) forecasts indicate that utility stock prices are expected to continue to be volatile, and these uncertainties in the market translate directly into higher costs of capital.[39]

14. Taken together, these indicators suggest that PacifiCorp's ROE should move upward from the current level set in 2006 as proposed by PacifiCorp, not downward as proposed by Staff and ICNU.

2. ICNU's Constant Growth DCF Method Using Analysts' Growth Rates and Corrected Risk Premium Method Support the Company's Proposed ROE.

15. The Commission consistently relies upon the DCF method when determining reasonable ROEs and found that "use of the simple constant-growth DCF method is generally preferable to the more complex and assumption-intensive multi-stage method."[40]

16. In this case, Mr. Gorman's constant-growth DCF analysis using analysts' growth rates yielded an ROE range of 10.45% to 10.50%.[41] These results are far closer to the Company's proposed 10.6% than Mr. Gorman's own 9.5%.

17. In both this case and the 2005 GRC, Mr. Gorman relied on the constant-growth DCF method using analysts' growth rates.[42] Indeed, in the Company's 2005 GRC, Mr. Gorman's DCF analysis was based solely on his constant-growth DCF model using analysts' growth rates.[43] Mr. Gorman's testimony in the 2005 GRC and in this case is virtually identical: "Security analysts' growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data because they are more reliable

---

[37] Gorman, Exh. No. MPG-1T 7:Fig. 1.
[38] Gorman, Exh. No. MPG-1T 6:22-24; 7:Fig. 1.
[39] Hadaway, Exh. No. SCH-1T 29: 1-33.
[40] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at ¶ 261 (Apr. 17, 2006).
[41] Gorman, Exh. No. MPG-1T 20:20-23.
[42] Gorman, TR. 448:24-449:12; Gorman, Exh. No. MPG-24 7:15-20. .
[43] Gorman, TR. 448:24-449:12.

estimates."[44] According to Mr. Gorman, these "are the most likely growth estimates that are built into stock prices."[45] Similarly, Dr. Hadaway relied upon analysts' forecasts because they are objective, verifiable forecasts from independent third parties.[46]

18. Mr. Gorman relied on his risk premium analysis to reduce his recommended ROE.[47] However, his analysis is flawed because he fails to take into account the well-established and empirically verified tendency for equity risk premiums to increase when interest rates are low and decrease when they are high.[48] Dr. Hadaway's testimony provided thorough and complete regression analysis to demonstrate this inverse relationship, which is altogether ignored in Mr. Gorman's testimony.[49] Dr. Hadaway's analysis persuasively demonstrated that when Mr. Gorman's risk premium method is corrected for this omission, it results in a midpoint ROE of 10.23%, a result closer to the Company's proposed ROE than his own.

3. Staff's ROE Recommendation in this Case is Unreasonable, as Demonstrated by a Comparison to Staff's ROE Analysis in the Most Recent ROE Litigation at the Commission.

19. The Commission's most recent litigated ROE was 10.1%, set in Puget Sound Energy, Inc.'s (Puget) last general rate case, Docket UE-090704 (Puget GRC), in April 2010.[50] In that case, Staff's witness David C. Parcell, recommended an ROE of 10.0%.[51] Staff's proposed ROE here is 50 basis points lower than Mr. Parcell's recommendation. A comparison of Staff's position in the two cases demonstrates the unreasonableness of Staff's recommendation here.

20. At the time that Mr. Parcell filed his testimony in the Puget GRC, single "A" utility

---

[44] Gorman, Exh. No. MPG-1T 19:20-22; Gorman, Exh. No. MPG-24 6:15-19; Gorman, TR. 472:9-473:4.
[45] Gorman, Exh. No. MPG-24 6:18-19.
[46] Hadaway, Exh. No. SCH-1T 35:4-7; *see also Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at ¶ 299 (Apr. 2, 2010) (growth estimates are unreliable if "obscure and not subject to replication").
[47] Gorman, Exh. No. MPG-1T 37 Table 4.
[48] Hadaway, Exh. No. SCH-8T 25:19-21.
[49] Hadaway, Exh. No. SCH-1T 40:1-13; Hadaway, Exh. No. SCH-7.
[50] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at 301 (Apr. 2, 2010).
[51] Elgin, Exh. No. KLE-5 2:18.

interest rates were 5.56%—exactly the same as the current interest rates.[52]

21. In the Puget GRC, Mr. Parcell used combined proxy groups consisting of a total of fifty-six companies.[53] In contrast, Staff witness Kenneth L. Elgin used a proxy group of only seven other utilities, because "a proxy group of twenty-two companies is simply too large and too complex for an investor to consider in making a rational investment decision."[54] This position is contrary not only to Mr. Parcell's approach, but also to Mr. Gorman's approach in this case,[55] and to Staff witness James A. Rothschild's approach in PacifiCorp's 2005 GRC,[56] where both Mr. Gorman and Mr. Rothschild accepted Dr. Hadaway's proposed proxy group.

22. In the Puget GRC, Mr. Parcell testified as to the complete, "raw" results of his DCF analysis without proposing any manual adjustments to these results. In contrast, Mr. Elgin proposed one or more manual adjustments to every one of his DCF results.[57] Mr. Elgin's adjustments likely resulted in a proxy group that was too small to be statistically reliable,[58] and produced growth estimates that are obscure and not subject to replication, which the Commission has previously rejected as unpersuasive.[59]

23. At hearing, Chairman Goltz noted that Mr. Elgin's ROE recommendation was 80 basis points below the 2010 national ROE mean and inquired whether this was evidence for not accepting his recommendation.[60] Mr. Elgin acknowledged that he "struggled" with this issue

[52] Elgin, TR. 700:11-21; Hadaway, Exh. No. SCH-1T 21:Table 1; Elgin, Exh. No. KLE-3 1.
[53] Elgin, TR. 702:20-23; Elgin, Exh. No. KLE-5 13-15.
[54] Elgin, Exh. No. KLE-1T 22:5-7; Elgin, Exh. No. KLE-1T 22:18-20.
[55] Hadaway, Exh. No. SCH-6; Gorman, Exh. No. MPG-1T 17:4-5.
[56] Elgin, Exh. No. KLE-6 3:6-16.
[57] Elgin, TR. 704:3-7;*see e.g.* Elgin, Exh. No. KLE-1T 30:15-31:4 (adjusting average dividend growth results down from 6.6% to 4.75%); *Id.* 31:17-23 (adjustment average book value growth rate up from 4.41% to 4.50%); *Id.* 32-43 (adjusting three of seven companies' results in "b times r" analysis to obtain 5.00%); *Id.* 36:8-12 (rejecting out of hand Value Line's earnings growth estimates of 7.00% and 8.00% as "too high"); *Id.* 37: 9-19 (adjusting Zacks and Thompson earnings estimates in the 5.6% to 6.0% to 5.50%); *Id.* 38:1-10 (without explanation removes 5.50% earnings per share growth rate from his analysis).
[58] *See* Hadaway, Exh. No. SCH-8T 13:2-9.
[59] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at ¶ 299 (Apr. 2, 2010).
[60] Elgin, TR. 734:16-23.

under the *Bluefield* case, but nevertheless advocated for a "strong order" resetting PacifiCorp's ROE below 10%.[61] This response suggests that Mr. Elgin's analysis was designed to support a low result, rather than to reflect an objective evaluation of the Company's current cost of equity.

4. Staff's and ICNU's Proposed ROE of 9.5% is Substantially Below Comparable ROEs.

24. The Commission has looked at comparative data to inform its ROE analysis.[62] As the Commission noted in PacifiCorp's last rate case, it was "mindful of the direction in *Bluefield* that" a utility's ROE must be equal to that of utilities with comparable risk.[63]

25. On November 19, 2010, the Commission approved a settlement in Avista's most recent rate case (Avista GRC) with an ROE of 10.2%.[64] Mr. Elgin included Avista in his proxy group because, "it has strong similarities to PacifiCorp."[65] While Avista's 10.2% ROE resulted from a settlement, the Commission has looked to approved settlements when examining comparable ROEs awarded other utilities.[66] Additionally, Staff's NPC witness relied upon the same Avista settlement to support his forced outage rate adjustment for the Colstrip plant, making it inconsistent for Staff to object to consideration of the Avista settlement in this limited context.[67]

26. In addition to the ROE decisions in 2010 in the Avista GRC and the Puget GRC, the Commission has approved ROEs of 10.2%, 10.2%, 10.2%, 10.15%, 10.4%, and 10.2% in recent

---

[61] Elgin, TR. 735:8-736:5.
[62] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at ¶ 263 (Apr. 17, 2006); *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-050482, Order 05 at n. 45 (Dec. 21, 2005) (average of authorized returns in other jurisdictions serves as a "useful check on the reasonableness of any range of cost of equity estimates derived for Avista").
[63] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692 (1923) ("A public utility is entitled to . . . earn a return . . . equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties")
[64] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-100467, Order 07 at ¶8 (Nov. 19, 2010).
[65] Elgin, Exh. No. KLE-1T 24:12:15.
[66] *See e.g. Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at ¶ 263 (Apr. 17, 2006).
[67] Buckley, Exh. No. APB-1T 16-18.

cases.[68] Nationally, average authorized electric utility ROEs ranged from 10.36% to 10.48% over the last five years.[69] When compared to ROEs awarded by this and other commissions, Staff's and ICNU's ROE recommendation fails the Commission's "common sense" test.[70]

5. The Company's Use of Long-term Gross Domestic Product (GDP) Growth Rates in Its DCF Analysis is Reasonable.

27. Messrs. Elgin and Gorman criticize Dr. Hadaway's use of a long-term GDP average to forecast growth rates in his multi-stage DCF analysis.[71] Mr. Elgin wrongly describes Dr. Hadaway's analysis as "simply us[ing] the average of the last 60 year cumulative decade averages of GDP growth as a proxy for his estimate of long-term dividend growth."[72] Dr. Hadaway's analysis did not use a "simple average," but rather explicitly gave more weight to more recent data because that has a greater effect on investor expectations.[73] As Dr. Hadaway explained, the use of historical data to identify economic trends and relationships is the basis of most econometric forecasts.[74] This is especially true in the case of DCF modeling because it requires a long-term constant growth rate.[75] The Commission has explicitly endorsed the use of forecasts *and historical data* when determining growth rates for DCF analysis.[76]

28. While critical of Dr. Hadaway's use of long-term historical data to develop a long-term

---

[68] As the Commission did in Docket UE-050684, this analysis here includes both litigated and settled rate cases. *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-090134, Order 10, ¶ 24 (Dec. 22, 2009) (10.2%); *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-090205 Order 09 at ¶ 23 (Dec. 16, 2009) (10.2%); *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-080416, Order 08 ¶ 15 (Dec. 29, 2008) (10.2%); *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-072300, Order 12 at ¶ 51 (Oct. 8, 2008) (10.15%); *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-060266, Order 08 at ¶ 81 (Jan. 5, 2007) (10.4%); *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at ¶ 264 (Apr. 17, 2006) (10.2%).

[69] Hadaway, Exh. No. SCH-8T 10 Table 3.

[70] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-040641, Order 06 at ¶ 80 (Feb. 18, 2005) (equity awards in other jurisdictions serve as a check that is "useful to fulfill the common sense approach").

[71] *See* Elgin, Exh. No. KLE-1T 55-56; Gorman, Exh. No. MPG-1T 44-46.

[72] Elgin, Exh. No. KLE-1T 55:9-13.

[73] Hadaway, Exh. No. SCH-1T 37:2-12. *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-040641, Order 06 at ¶ 44 (Feb. 18, 2005) (DCF requires a growth component that reflects "what investors actually, and reasonably, expect.").

[74] Hadaway, Exh. No. SCH-1T 37:18-20.

[75] *See* Elgin, Exh. No. KLE-1T 25:11-13.

[76] *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at ¶ 300 (Apr. 2, 2010) (DCF results are persuasive when based upon "both forward-looking estimates and historical data").

forecast, both Messrs. Elgin and Gorman testified that the GDP growth rate should be based on short-term forecasts (5-to-10 years).[77] However, these forecasts give too much weight to outlier data from the financial crisis and unusually low rates of inflation.[78] Because the DCF analysis assumes a growth rate for the long-term, it is unreasonable to use a forecast that is unduly influenced by recent events that are not expected to persist for the long-term.[79] Mr. Elgin acknowledged that the growth rate must be "what could be maintained in the long term."[80]

29. Mr. Gorman's criticism of the use of a long-term GDP growth rate is particularly troubling. When discounting his own 10.5% constant growth DCF ROE results that used analysts' growth rates (which he expressly testified are superior), Mr. Gorman indicated that the analysts' growth rates exceeded a "long-term sustainable growth rate as required by the constant growth DCF model."[81] Thus, he discounted his constant growth DCF analysis because of the shorter-term focus of analysts' forecasts, but then proposes a GDP growth rate relying on similar short-term forecasts.[82]

30. Mr. Elgin also criticized the use of a long-term GDP historical average in the DCF model because he claimed that it was "contrary to the Commission's order in PacifiCorp's [2005] rate case."[83] However, in the 2005 GRC, the Commission noted that it did "not take issue with Dr. Hadaway's opinion that the DCF formula requires a long-term growth rate or that growth in GDP may serve as a better measure of long-term growth than analysts' forecasts in the short-term."[84] Only after making these statements did the Commission then conclude that *in that case*

[77] Elgin, Exh. No. KLE-1T 55:21-56:6; Gorman, Exh. No. MPG-1T 45:Table 6.
[78] Hadaway, Exh. No. SCH-8T 21:6-20.
[79] Hadaway, Exh. No. SCH-8T 25:9-11.
[80] Elgin, TR. 705:1-14.
[81] Gorman, Exh. No. MPG-1T 21:3-4.
[82] Gorman, TR. 472:9-473:4; Gorman, Exh. No. MPG-1T 45 Table 6 (long-term growth rate should be based upon 5- and 10-year GDP forecasts).
[83] Elgin, Exh. No. KLE-1T 55:15-20.
[84] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at ¶ 261 (Apr. 17, 2006).

shorter-term GDP growth forecasts should be used. Here, the use of a shorter-term GDP growth forecasts is problematic because those forecasts are unduly influenced by recent economic events and conditions. In the years prior to the 2005 GRC, the economy did not experience what it has experienced prior to this case—the market turbulence since 2008 has been the greatest seen since the 1930s.[85] Therefore, *in this case* the use of weighted long-term historical averages to forecast future, long-term GDP growth rates certainly is appropriate.

6. Given the Unusual Financial Circumstances of this Post-Financial Crisis Period, it was Reasonable for PacifiCorp Not to Include Capital Asset Pricing Model (CAPM) Results.

31. While both Messrs. Gorman and Elgin included in their analysis the results of their CAPM calculations,[86] only Mr. Gorman relied on his CAPM results to reduce his ROE recommendation.[87] Dr. Hadaway did not include a CAPM analysis because of his opinion that the model would produce artificially low results (*i.e.* between 7% and 9%) under current economic conditions.[88]

32. In the recent Puget GRC, the Commission concluded that "in these unusual financial circumstances we have accorded the CAPM results diminished weight."[89] The "unusual financial circumstances" that existed as of April 2010 when the Commission made this statement continue today. The government's "easy money" policies, the volatility of utility stock prices, and the relatively poor market performance of utility stocks all result in understated inputs to the CAPM model.[90] Mr. Gorman's CAPM results are a full 105 basis points below his DCF analysis and 66 basis points below his risk premium analysis.[91] In PacifiCorp's 2005 GRC, the

[85] Hadaway, Exh. No. SCH-1T: 19:6-17.
[86] *See* Elgin, Exh. No. KLE-1T 38-44; Gorman, Exh. No. MGP-1T 32-37.
[87] Elgin, Exh. No. KLE-1T 44:3-5 (". . . I do not recommend the Commission place high reliance on the CAPM.").
[88] Hadaway, TR. 249:10-25.
[89] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at n. 369 (Apr. 2, 2010).
[90] Hadaway, Exh. No. SCH-8T 10:22-11:15.
[91] Gorman, Exh. No. MPG-1T 37 Table 4.

Commission discouraged reliance on such outlier results: "We find these extreme values to be of little practical use."[92]

B. Capital Structure

33. The capital structure established by the Commission for ratemaking purposes must balance "debt and equity on the bases of economy and safety," reviewing the economy of lower cost debt versus the safety of higher cost common equity.[93] Generally, the Commission's goal is to "set the Company's equity ratio at the level that the evidence shows is most likely to prevail, on average, over the course of the rate year."[94] The Commission will use hypothetical capital structures, *i.e.*, capital structures that deviate from actual rate year capital structures, "when there [is] a clear and compelling reason to do so."[95]

34. The evidence supports the Company's proposed a capital structure consisting of 52.1% common equity, not Staff's proposed common equity ratio of 46.5% or ICNU's proposed 49.1%.

1. The Company's Proposed Equity Ratio is its Actual Equity Ratio.

35. The Company's proposed capital structure is based upon the average of the five-quarters ending December 31, 2010.[96] A 52.1% equity ratio reflects the actual equity ratio that will be in effect during the rate year, a fact no party disputed.[97] PacifiCorp's equity ratio has grown over the last several years in response to more stringent requirements for maintaining its "A" credit

---

[92] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at n. 384 (Apr. 17, 2006).
[93] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-040641, Order 06 at ¶ 27 (Feb. 18, 2005).
[94] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-040641, Order 06 at ¶ 40 (Feb. 18, 2005) (Commission rejected hypothetical rate structure noting: "Our goal in this proceeding should be to set the Company's equity ratio at the level that the evidence shows is most likely to prevail, on average, over the course of the rate year.").
[95] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-060266, Order 08 at ¶ 76 (Jan. 5, 2007). The Commission subsequently affirmed this standard in Puget Sound Energy's next general rate case. *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at ¶ 278 (April 2, 2010); *see also Wash. Utils. & Transp. Comm'n v. Avista*, Docket UE-050482, Order 05 at ¶ 55 (Dec. 21, 2005) ("The Commission has approved 'hypothetical' equity components in capital structures in the past when there was good reason to do so. In this case, our purpose is to support the Company's continuing efforts to strengthen its balance sheet and restore its credit rating to investment grade.").
[96] Williams, Exh. No. BNW-1T 7:6-7.
[97] Gorman, Exh. No. MPG-1T 13:13-15.

rating.[98] Consistent with Commission precedent, this actual equity ratio should be used unless there is a "clear and compelling reason" for establishing a hypothetical capital structure.

2. Staff Provides No Compelling Reason to Adopt a Hypothetical Capital Structure.

36. Staff proposes a 4% reduction in the actual common equity ratio because other utilities have similar equity levels, in recent proceedings the Commission has approved similar equity levels, and it is consistent with the equity level in the Company's last two rate cases.[99] These are not compelling reasons to adopt a hypothetical capital structure. First, Mr. Elgin's ROE proxy group, a group he selected because they are comparable to PacifiCorp,[100] has an average projected common equity ratio of 50.4%.[101] Second, when comparing the Company's equity ratio to other Washington utilities, Mr. Elgin makes no allowance for the fact that PacifiCorp has no power cost adjustment mechanism (PCAM) or energy cost adjustment mechanism (ECAM) in Washington. This is inconsistent with the fact that when the Company sought a PCAM in its 2006 general rate case, Docket UE-061546 (2006 GRC), Mr. Elgin recommended a 4% reduction in equity ratio to account for decreased operational risk.[102]

3. ICNU Provides No Compelling Reason to Adopt a Hypothetical Capital Structure.

37. ICNU proposed a capital structure that includes 49.1% common equity. ICNU failed to demonstrate a clear and compelling basis for adoption of its hypothetical capital structure and instead relied upon arbitrary adjustments that lack a sound financial basis.[103]

38. The first flaw in Mr. Gorman's analysis is his use of the most recent five quarters ending June 30, 2010, as the starting point, instead of the more current period used by the Company

[98] Williams, Exh. No. BNW-1T 4:19-22.
[99] Elgin, Exh. No. KLE-1T 16:13-19.
[100] Elgin, Exh. No. KLE-1T 23:1-2.
[101] Williams, Exh. No. BNW-7T 9:8-10.
[102] Elgin, Exh. No. KLE-4 3:6-9.
[103] Williams, Exh. No. BNW-7T 17:18-20.

(five quarters ending December 2010).[104]

39. Mr. Gorman also removed $158 million in acquisition adjustments from the equity component of the capital structure because he alleged that these relate to generating plants outside the western control area.[105] His proposed adjustment included significant errors,[106] and removal of these amounts from PacifiCorp's equity component is improper because the Company finances its operations and receives a credit rating on an overall capital structure, not a state-by-state structure. If Mr. Gorman's method is to be adopted it would require additional adjustments that exclude favorable, non-WCA items from the capital structure.[107]

40. Mr. Gorman also proposes a reduction in equity to reflect the removal of certain short-term investments.[108] This proposal is wrong for two reasons. First, Mr. Gorman nets short-term investments against common equity rather than the accepted practice of netting against long-term debt to determine "net debt." Mr. Gorman's proposal is highly unusual and not supported in general financial theory or practice.[109] Second, the Company exhausted its temporary cash investments in September 2010, and therefore this proposed adjustment is moot.[110]

41. Mr. Gorman's analysis is also flawed because he asserts that these short-term investments represent a placeholder for retained earnings.[111] This is incorrect. The facts demonstrate that PacifiCorp is investing more into its business than its cash flow from operations.[112]

4. ICNU's Hypothetical Capital Structure Fails to Account for the Lack of a PCAM and is Inconsistent with Mr. Gorman's Position in Other Cases.

42. In Mr. Gorman's cross-answering testimony filed on November 5, 2010, he criticized

[104] Gorman, Exh. No. MPG-1T 13:12-13.
[105] Williams, Exh. No. BNW-7T 18:16-21.
[106] Williams, Exh. No. BNW-7T 19:5-10.
[107] Williams, Exh. No. BNW-7T 18:21-19:4.
[108] Gorman, Exh. No. MPG-1T 13:17.
[109] Williams, Exh. No. BNW-7T 19:13-19.
[110] Williams, Exh. No. BNW-7T 19:13-19.
[111] Gorman, Exh. No. MPG-1T 14: 24-26.
[112] Williams, Exh. No. BNW-7T 20:19-21.

PacifiCorp's equity build-up as "more than necessary to fund its utility plant investments."[113] When testifying before the Wyoming Public Service Commission five days later, Mr. Gorman acknowledged that PacifiCorp's equity ratio was over 50%, which he stated was "significant because increasing common equity ratio reduces financial risk to help balance total investment risk for the operating risk related to not being given full guaranteed cost recovery of power cost[s]."[114] As Mr. Gorman testified, the objective is to balance financial risk, which is decreased by increasing the common equity ratio, with operational (or business) risk, which is decreased by allowing a PCAM.[115] In Washington, PacifiCorp has no PCAM and is therefore exposed to greater operational/business risk. This exposure necessitates, in Mr. Gorman's words, mitigation in the form of increased common equity, *i.e.*, reduced financial risk. Therefore, according to Mr. Gorman's testimony in Wyoming, the Company's increased equity ratio beyond 50% is reasonable as a means to "ensure[] that the financial and operating risk of the utility are structured in a way that . . . maintains investment grade credit quality."[116]

43. During cross-examination, Mr. Gorman disavowed his Wyoming testimony, claiming he either misspoke or the transcript was incorrect.[117] When pressed, however, Mr. Gorman stood by his testimony quoted above that increased equity in PacifiCorp's capital structure helps to balance operating risk associated with recovery of power costs in a non-PCAM environment.[118]

5. The Commission Should Exclude Short-Term Debt Because the Company Has None.

44. As part of Mr. Elgin's hypothetical capital structure, he proposed the Commission impute 3% of the capital structure as short-term debt. The Company's actual capital structure for the

[113] Gorman Exh No. MPG-22T 4: 1-2.
[114] Gorman, Exh. No. MPG-26 4:18-25.
[115] Gorman, Exh. No. MPG-26 5:1-6.
[116] Gorman, Exh. No. MPG-26 5:21-24.
[117] Gorman, TR. 455:15-457:16.
[118] Gorman, TR. 457:17-22.

rate year includes no short-term debt because the Company recently issued long-term debt and has received capital contributions from its parent company.[119] The Company has not carried a material amount of short-term debt,[120] and even Mr. Gorman acknowledges that the Company's actual capital structure does not include short-term debt to finance rate base.[121] Given the problems caused by the financial crisis especially in the short-term markets, the Company's decision to rely on favorably priced long-term debt was prudent and reasonable.[122] Mr. Elgin also erroneously conflates the Company's short-term debt facilities with actual short-term debt.[123]

45. Mr. Elgin testified that the Commission should include 3% short-term debt here because that is what it did in the 2005 GRC.[124] In that case, however, the Company actually had short-term debt outstanding and the Commission included a component of short-term debt because it had traditionally done so "based on a company's *actual capital structure*."[125] Basing the capital structure on the "company's actual capital structure" in this case, and recognizing that the Company is not improperly employing short-term sources of funds to finance long-term assets, the Commission should reject Staff's imputation of short-term debt.

C. Credit Metrics Under Staff's and ICNU's Cost of Capital Proposals.

1. The Proposed Hypothetical Equity Ratios Would Downgrade the Company's Credit Rating.

46. The Company's current equity ratio is intended to allow it to maintain its current credit

---

[119] Williams, Exh. No. BNW-7T 4:17-19.
[120] Williams, Exh. No. BNW-1T 4:1-2.
[121] Gorman, TR. 464:10-18.
[122] Williams, TR. 279:12-25.
[123] Elgin, Exh. No. KLE-1T 19:12.
[124] Elgin, Exh. No. KLE-1T 19:19-22.
[125] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at ¶ 224 (Apr. 17, 2006) (emphasis added).

ratings, resulting in lower overall financing costs to customers[126]and uninterrupted access to capital markets. Mr. Elgin testified that "a reasonable equity ratio is in the mid 40% range, supporting a 'BBB' rating on corporate debt and an 'A-' secured credit rating."[127] He recommends an equity ratio of 46.5% because that ratio "is sufficient to support a solid BBB corporate credit rating."[128] Mr. Elgin thus recommends a capital structure that he acknowledges will result in a credit downgrade.[129] To support his proposed downgrade, Mr. Elgin stated that only about one in four utilities have an "A" rating and therefore PacifiCorp's downgrade would place it in the majority of nation-wide utilities.[130] His analysis fails to account for the industry-wide trend towards increasing equity ratios, as independently confirmed by a recent S&P report and acknowledged by the Commission in the Company's 2005 GRC.[131]

47. Mr. Gorman's analysis also supports the Company's position that a credit downgrade and increased capital costs are real risks if the proposed hypothetical equity ratios are adopted. Mr. Gorman testified before the Iowa Utilities Board in September, 2010, that a 50% equity ratio would support an "A" credit rating, which "would help minimize the utility's overall cost of capital . . . which in turn help[s] maintain the utility's access to external capital markets."[132] In this case, Mr. Gorman's original credit metrics analysis acknowledged that his proposed debt ratio of 51% "might deteriorate [PacifiCorp's] credit rating."[133] Accounting for an error in his calculations, Mr. Gorman modified his debt ratio from 51% to 52%, making the risk even greater

[126] *See* Williams, Exh. No. BNW-1T 10:1-19; Williams, Exh. No. BNW-7T 5:3-8; 11:20-23, 12:3-17.
[127] Elgin, Exh. No. KLE-1T 15:19-20.
[128] Elgin, Exh. No. KLE-1T 16:17-19.
[129] This is especially true because PacifiCorp is already viewed as a "BBB" on a stand-alone basis. So any adjustment that puts downward pressure on the rating is more likely to cause a downgrade than it would be for a company without this stand-alone rating. Williams, Exh. No. BNW-1T 9:8-12.
[130] Elgin, Exh. No. KLE-1T 15:15-16.
[131] Williams, Exh. No. BNW-7T 16:4-22; *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 at ¶ 232 (Apr. 17. 2006).
[132] Gorman, TR. 460:16-24; Gorman, Exh. No. MPG-25 9:8-16.
[133] Gorman, Exh. No. MPG-1T 40:20-41:2.

that a downgrade will occur if Mr. Gorman's proposed hypothetical equity ratio is adopted.[134]

2. Staff's Analysis of the Safety of its Cost of Capital Recommendation is Unpersuasive.

48. Mr. Elgin uses a pretax interest coverage ratio to test the safety of his cost of capital recommendations.[135] As explicitly acknowledged by Mr. Parcell in the Puget GRC, this metric has not been relied upon by credit ratings agencies for more than 10 years;[136] Mr. Elgin's testimony fails to mention this important fact.

49. Second, Mr. Elgin's ratio analysis is purely hypothetical and assumes that his authorized cost of capital translates into actual performance.[137] Mr. Elgin's testimony indicated that safety is determined based upon whether the authorized cost of capital meets or exceeds a 2 times pretax coverage ratio.[138] To fall below 2 times, Mr. Elgin testified that PacifiCorp's ROE would have to "fall significantly," to below 4%.[139] In the Company's 2006 GRC, Mr. Elgin concluded that if the coverage ratio fell below 2.5 times, then the Company's ability to access capital would be threatened.[140] Using the 2.5 times coverage ratio from Mr. Elgin's past testimony moves the ROE trigger from 4% to 6.77%.[141] Here, the evidence is undisputed: PacifiCorp's ROE in the test period is well below this 6.77% level, reinforcing the danger of Mr. Elgin's recommendations in Washington where PacifiCorp historically has fallen far short of earning its allowed ROE.

3. ICNU's Analysis of the Safety of its Cost of Capital Recommendation is Unpersuasive.

50. Mr. Gorman argues that his analysis demonstrated that adoption of his 9.5% ROE will

[134] Gorman, Exh. No. MPG-23; Gorman, TR. 461:12-18; Gorman, TR. 462:2-7.
[135] Williams, Exh. No. BNW-7T 13:9-21.
[136] Elgin, Exh. No. KLE-5 17.
[137] Williams, Exh. No. BNW-7T 14:1-7.
[138] Elgin, Exh. No. KLE-1T 17:21-18:4.
[139] Elgin, Exh. No. KLE-1T 17:21-18:4.
[140] Elgin, Exh. No. KLE-4 12-13.
[141] Elgin, TR. 715:12-20.

allow the Company to maintain its current credit rating.[142] However, Mr. Gorman admitted that his analysis failed to consider approximately $500 million in off-balance sheet obligations included by S&P in its analysis.[143] This omission is significant enough to undermine all other aspects of the analysis. Mr. Gorman also ignored the rating agencies explicitly stated expectations for PacifiCorp when trying to support the flawed results of his modeling effort.[144]

51. Contrary to Mr. Gorman's conclusions, there is a very real risk of a credit downgrade if the ROE is set at 9.5%. According to S&P, the Company's current stand-alone credit rating is already more in line with a "BBB" rating.[145] This risk is further exacerbated because the Company's increasing capital expenditures require better financial metrics to maintain the current ratings.[146]

52. Moreover, the costs to customers in the event of a credit downgrade are both real and substantial. As Mr. Williams testified, a solid credit rating allows the Company to access critical debt markets and to do so at lower costs.[147] Indeed, if the Company had been rated "BBB" since the acquisition by MEHC in 2006, the increased cost of debt attributed to the downgraded rating alone is estimated to be $30 million more in annual interest expense.[148] The Commission acknowledged the significant costs associated with credit downgrades as recently as last November, when it noted in approving Avista's settlement of its 2010 rate case: "Stronger credit ratings will result in lower long-term costs to Avista's customers and should allow longer intervals between general rate cases."[149]

---

[142] Gorman, Exh. No. MPG-1T 38:2-6.
[143] Gorman, TR. 463:3-7; Williams, Exh. No. BNW-7T 21:6-14.
[144] Williams, Exh. No. BNW-7T 22:2-13; Gorman, Exh. No. MPG-1T 9, 11.
[145] Williams, Exh. No. BNW-1T 9:8-12.
[146] Williams, Exh. No. BNW-7T 10:5-6.
[147] Williams, Exh. No. BNW-1T 10:1-19.
[148] Williams, Exh. No. BNW-7T 12:3-9.
[149] *Wash. Utils. & Transp. Comm'n v. Avista Corp.* Docket UE-100467, Order 07 at n. 37 (Nov. 19, 2010).

IV. REVENUE ADJUSTMENTS

A. Residential Revenues Should Be Based on Temperature Normalized Usage.

53. ICNU/Public Counsel recommend increasing the level of residential revenues by approximately $2.2 million.[150] ICNU/Public Counsel witness Mr. Meyer argued that revenues should be annualized based on the actual average usage per customer over the previous five years.[151] In contrast, Staff and the Company agree that, consistent with Commission precedent, residential revenues should be calculated using temperature normalized usage.[152]

54. As Staff witness Ms. Novak testified, temperature normalization is necessary because many of PacifiCorp's customers use electricity for space heating and changes in temperature may have a significant impact on these customers' usage.[153] The temperature normalization adjustment ensures that if the test year was warmer than usual, rates will not be set too high, and if the test year was colder than usual, rates will not be set too low.[154] The purpose of the adjustment is to calculate revenues on the basis of normal temperatures based on temperatures measured at the Yakima weather station.[155]

55. ICNU/Public Counsel's proposal results in an unreasonably high level of residential usage. Mr. Meyer's methodology assumes that residential loads in Washington are not affected by temperature.[156] As Staff witness Mr. Schooley testified, temperature is in fact the primary

---

[150] Meyer, Exh. No. GRM-1CT 16:4-5.
[151] Meyer, Exh. No. GRM-1CT 16: Table 3, 1-5.
[152] Schooley, Exh. No. TES-4T 4:11-15; Duvall, Exh. No. GND-5T 11:10-22. ICNU's and Public Counsel's proposal also differs from Staff's and the Company's in that it uses five years of usage rather than test year usage and reverses out-of-period adjustments made by the Company. Duvall, Exh. No. GND-5T 19-22.
[153] Novak, Exh. No. VN-1CT 3:22-4:3.
[154] Novak, Exh. No. VN-1CT 4:4-7.
[155] Novak, Exh. No. VN-1CT 4:7-9. Ms. Novak's pre-filed testimony indicated that PacifiCorp determines normal temperature using data from the Portland Airport weather station. Novak, Exh. No. VN-1CT 4:19.20. PacifiCorp explained at the hearing that the Company measures weather at the Yakima weather station. Novak, TR. 767:22-23.
[156] Duvall, Exh. No. GND-5T 12:14-15.

influence on residential customer usage.[157] As a result, nearly all of the increase in residential usage from the 12-month period ended June 2008 to the 12-month period ended December 2009 was due to temperature differences.[158] Failing to account for these temperature differences will result in rates that are set too low based on normal temperatures.

56. Moreover, Mr. Meyer's proposal does not account for all increased costs that would result from increasing residential usage. While Mr. Meyer offsets increased revenues for fuel,[159] his adjustment ignores other costs and effects on allocation factors and the production factor.[160] Indeed, a change in loads for the test period would require recalculation of NPC, allocation factors and the production factor. It would also impact the class cost of service study results.

57. Finally, ICNU/Public Counsel's proposal is inconsistent with the temperature normalization methodology approved by the Commission in Docket UE-050684 and accepted by ICNU and Public Counsel in the Company's 2009 rate case.[161] In the 2009 rate case stipulation, ICNU and Public Counsel reserved the right to propose changes to the Company's temperature normalization methodology or a new methodology "if they believe the underlying data is insufficient, or if [they] believe[] new information comes to light."[162] Mr. Meyer's testimony does not explain that the temperature normalization methodology is insufficient or that new information has come to light—in fact, he does not discuss the Company's temperature normalization methodology at all.[163]

58. At the hearing, Commissioner Oshie questioned Staff witness Mr. Schooley on the implication of the R-squared statistic of 0.976 produced by the Company's residential weather

---

[157] Schooley, Exh. No. TES-4T 4:19.
[158] Schooley, Exh. No. TES-4T 5:1-16.
[159] Meyer, Exh. No. GRM-1CT 18:12-13.
[160] Schooley, Exh. No. TES-4T 6:3-8.
[161] Duvall, Exh. No. GND-5T 12:15-13:4; *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-090205 Order 09, Stipulation ¶ 19 (Dec. 16, 2009).
[162] *Id.*
[163] *See* Meyer, Exh. No. GRM-1CT 16:2-18:13.

normalization regression model.[164] While the discussion suggested that the 0.976 R-squared was interpreted by some as indicating that the Company's residential temperature normalization had a margin of error of 2.4%, that is not the meaning of the R-squared statistic. As Ms. Novak's testimony indicates, the statistic here means 97.6% of the total variation in residential use per customer consumption was explained by the independent variables, leaving approximately 2.4% of the variation in dependent variable as "unexplained."[165] Because the R-squared statistic measures the strength of the relationship between dependent and independent variables, it cannot be used to measure the difference in accuracy between Mr. Meyer's residential use per customer and the Company's weather normalized use per customer.

B. The Company's Temperature Normalization of the Commercial Class Increases the Accuracy of the Estimate of Commercial Class Usage.

59. Staff proposed that the Commission reject the Company's commercial class temperature normalization adjustment on the basis that the Company has not adequately defended its methodology.[166] Staff argues that the R-squared statistic of 0.644 does not demonstrate a good statistical fit.[167]

60. The Company recommends that the Commission reject Staff's proposal. Staff agrees that the commercial class is a temperature-sensitive class and that the Company used the temperature normalization methodology agreed upon by parties in a stipulation approved by the Commission in Docket UE-050684.[168] PacifiCorp's temperature normalization of the commercial class results in an R-squared of 0.644, which means that 64.4% of the variation in load is explained by variations in temperature.[169] Moreover, removing the Company's temperature normalization

[164] Schooley, TR. 798:7-799:2.
[165] Novak, Exh. No. VN-1CT 7:17-21; 8:1-3.
[166] Novak, Exh. No. VN-1CT 9:17-21; 10:19-22.
[167] Novak, Exh. No. VN-1CT 8:10-16.
[168] Novak, Exh. No. VN-1CT 9:12-15; 2:14-15.
[169] Duvall, Exh. No. GND-5T, 10:14-17.

adjustment results in a decline in the R-squared value from 0.64 to 0.58.[170] This means that Staff's proposal would *decrease* the accuracy of the commercial class load forecast.[171]

61. While the Company objects to the adoption of Staff's adjustment in this case, it recommends that Staff, the Company, and other interested parties to work together to improve the commercial class temperature normalization adjustment for use in future filings.[172]

C. The Company's Rebuttal Filing Reflects Staff's and ICNU's Renewable Energy Credit (REC) Adjustments and Accurately Reflects Expected REC Revenues.

62. In the rebuttal testimony of Mr. Duvall, the Company agreed to include in base rates a revenue credit for Washington-allocated RECs it expects to sell in the rate effective period.[173] The Company's adjustment reduced the Washington revenue requirement by approximately $5.0 million,[174] an adjustment greater than Staff's base rate adjustment of $4.2 million[175] and approximately equal to ICNU's base rate adjustment of $4.9 million.[176] While the Company did not use the same methodology proposed by Staff or ICNU in calculating its REC adjustment, the Company's adjustment effectively resolves these base rate adjustments.[177]

63. Staff also proposed that in addition to the base rate adjustment for REC revenues, the Company be required to record all REC revenues beginning on January 1, 2010 as a regulatory liability, with the Commission addressing the ratemaking treatment of these deferred revenues in a future case.[178] The Company objects to Staff's proposal to retroactively track for inclusion in rates REC revenues received by the Company prior to the effective date of rates in this case.

64. For support of the proposal to retroactively recover 2010 REC revenues, Staff relies on

---

[170] Duvall, Exh. No. GND-5T, 10:18-23.
[171] Duvall, Exh. No. GND-5T, 10:21-23.
[172] Duvall, Exh. No. GND-5T, 11:1-5.
[173] Duvall, Exh. No. GND-5T 3:20-4:4.
[174] Dalley, Exh. No. RBD-4T 9:2-3.
[175] Foisy, Exh. No. MDF-1CT 10:20-21.
[176] Falkenberg, Exh. No. RJF-1CT 63:14-15.
[177] Duvall, Exh. No. GND-5T 5:6-10.
[178] Foisy, Exh. No. MDF-1CT 10:21-11:2.

the Commission's recent order in a Puget case resolving Puget's request to defer revenues from the sale of certain RECs and to use the revenues in a specific manner.[179] Staff stated that the Commission recognized in that order that gains on the sale of RECs "should go to the ratepayers absent unusual or extraordinary circumstances."[180]

65. While the Puget order indicates that customers are generally entitled to a revenue credit for REC sales, the order does not authorize discarding established ratemaking principals, such as the doctrine against retroactive ratemaking, when calculating a REC revenue adjustment. The Commission has previously stated that "retroactive ratemaking . . . is extremely poor public policy and is illegal under the statutes of Washington State as a rate applied to a service without prior notice and review."[181] The doctrine "prohibits the Commission from authorizing or requiring a utility to adjust current rates to make up for past errors in projections."[182] Importantly, the doctrine was not implicated in the Puget case, because Puget had filed an accounting petition seeking to defer the proceeds of REC sales in 2007.[183]

66. In this case, no party has filed a deferral petition for PacifiCorp's 2010 REC revenues. As a result, Staff's proposal to require PacifiCorp to record a regulatory liability for REC revenues received prior to the Commission's order in this proceeding violates the rule against retroactive ratemaking.[184] The rule similarly bars PacifiCorp from seeking to reflect in rates

[179] Foisy, Exh. No. MDF-1CT 10:5-13; *Re. Petition of Puget Sound Energy, Inc.*, Docket UE-070725, Order 3 ¶ 1 (May 20, 2010).
[180] Foisy, Exh. No. MDF-1CT 10:7-9.
[181] *Re Puget Sound Energy*, Docket UE-010410, Order Denying Petition to Amend Accounting Order (Nov. 9, 2001); *see also* RCW 80.28.020. The Commission denied Puget's petition on the basis that the "retroactive ratemaking doctrine prohibits the Commission from authorizing or requiring a utility to adjust current rates to make up for past errors in projections. With few exceptions (not applicable here), under RCW 80.28.020, the Commission is charged with setting rates on a prospective basis."
[182] *Id.*
[183] *Re. Petition of Puget Sound Energy, Inc.*, Docket UT-070725, Order 3 ¶ 6 (May 20, 2010).
[184] The Commission has indicated that recovery of costs incurred prior to the date of the filing of an accounting petition "undeniably would violate the general prohibition against retroactive ratemaking and thus is not a legally sustainable result." *In re PacifiCorp*, Docket UE-020417, Sixth Supp. Order(July 15, 2003) (referring to the $98 million in power costs incurred prior to PacifiCorp's deferred accounting filing).

costs it under recovered in 2010.

67. Even if Staff's proposal did not constitute retroactive ratemaking, establishing a regulatory liability account would be inappropriate for other reasons. First, absent a true-up mechanism, including REC revenues in base rates while tracking the revenues through a regulatory liability account would double count REC revenues.[185] Second, Staff's proposal violates the matching principle because it does not propose to track actual NPC, although RECs and megawatt hours are generated from the same source at the same time.[186] The Commission previously rejected the Company's proposal for a PCAM on the basis that the WCA methodology results in "pseudo" actual power costs, a concern that is similarly implicated by a proposal to track "pseudo" revenues related to "pseudo" RECs.[187]

V. NET POWER COST ISSUES

A. Introduction

68. The Company is requesting NPC of $554.3 million on a WCA basis, or $125.5 million on a Washington-allocated basis. This amount is a reduction from the $557.6 million WCA NPC included in the Company's rebuttal filing,[188] which resulted from the Company's update to NPC

[185] Duvall, Exh. No. GND-5T 6:1-9.
[186] Duvall, Exh. No. GND-5T 6:12-16. The PSE case addresses the matching principle. While Puget's REC deferral petition was pending, Public Counsel and Kroger attempted to bring the REC sales issue into Puget's general rate case. Puget, Staff and the Energy Project moved to strike this testimony on the basis that REC issues were outside the scope of the general rate case. Public Counsel argued that "REC revenue issues are directly related to the proper analysis of power costs in this case...[W]hen wind generation costs are included in the power costs sought to be recovered, proper ratemaking principles requires that revenues derived from the related RECs must also be considered. Moreover, Joint Movants do not explain why it is appropriate to update PSE power costs as was done in the most recent supplemental filing, without updating related revenues. Failure to take these known and measurable revenues into account would be a violation of the matching principle." The Commission acknowledged the merit of Public Counsel's argument, but granted the motion to strike, finding that the pendency of the deferred accounting docket on RECs ensured against harm to customers. *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-090704, Order 10 (January 8, 2010).
[187] "Pseudo" RECs exist due to the fact that RECs cannot be allocated to more than one state and RECs are allocated on a system-wide basis to each state that is supporting the costs of the facility from which the RECs are generated. Even if the Company could meet its Washington renewable portfolio standard from the total RECs generated from facilities located in Washington, other states are paying a share of the costs of these facilities are therefore entitled to a share of the RECs that are generated. Duvall, Exh. No. GND-5T 6:17-7:6.
[188] Duvall, Exh. GND-5T 14:5-6.

for the December 2010 forward price curve and to remove the Chehalis reserve adjustment, as described in the Company's Response to Bench Request 3.[189] For reference, Staff's and ICNU's proposed adjustments to the Company's requested level of NPC are set forth in Appendix B.

B. ICNU's and Staff's Adjustments for Arbitrage Margins Have Multiple Flaws.

69. Staff and ICNU propose an adjustment intended to account for margins earned on actual arbitrage transactions.[190] Staff's adjustment of $2.4 million[191] is based on 90% of the four-year average to provide an incentive for the Company, while ICNU's adjustment of $2.6 million is based on 100% of the four-year average.[192]

70. The Company objects to these adjustments because they double count revenues associated with arbitrage transactions already embedded in the GRID model,[193] and are a selective departure from normalized ratemaking. Neither Staff nor ICNU propose including short-term trading transactions in their adjustments.[194] Both parties conceded that doing so would reduce the amount of their proposed adjustments by approximately $1 million.[195] While ICNU witness Mr. Falkenberg cites an Oregon Public Utility Commission order to justify his proposal,[196] the adjustment in Oregon includes short-term trading revenues.[197]

71. Mr. Falkenberg states that the Company's use of a "forecast period more advanced into the future than in any of the Company's recent cases" justifies ICNU's arbitrage adjustment.[198] In fact, as Mr. Falkenberg conceded on cross-examination, the forecast period for NPC in this

[189] Bench Request, Exh. No. 16C.
[190] Buckley, Exh. No. APB-1CT 8:7-12; Falkenberg, Exh. No. RJF-1CT 9:20-22.
[191] All NPC adjustments are stated on a WCA basis, rather than a Washington-allocated basis.
[192] Buckley, Exh. No. APB-1CT 8:6-15; Falkenberg, Exh. No. RJF-1CT 9:20-22.
[193] Duvall, Exh. No. GND-5T 31:18-20.
[194] Buckley, Exh. No. APB-1CT 8:7-21; Falkenberg, Exh. No. RJF-1CT 9:4-5.
[195] Falkenberg, TR 667:6-12.
[196] Falkenberg, Exh. No. RJF-1CT 10:3-24.
[197] Falkenberg, TR 666:15-667:21.
[198] Falkenberg, Exh. No. RJF-1CT 6:6-10.

case is no farther into the future than in the Company's prior rate case.[199] In PacifiCorp's 2006 rate case, the Commission rejected Mr. Falkenberg's adjustment disallowing short-term firm transactions, which was based on the same rationale (*i.e.*, that forecasted NPC did not properly account for short-term transactions).[200]

72. Finally, it is clear that if based upon the most recent year of historical data, the arbitrage margin adjustment would be much smaller.[201] This undermines the basis for the adjustment in the first instance.

C. Transmission Adjustments

1. ICNU's Adjustments to the Commission-Approved WCA Methodology Should be Rejected.

73. ICNU Adjustments 3 and 4 address allocation of costs and benefits between the Company's east control area (PACE) and west control area (PACW).[202] These adjustments relitigate issues decided when the Commission approved the WCA inter-jurisdictional cost allocation methodology in the 2006 GRC.[203] The Commission established the WCA methodology on a five-year evaluation period and subject to an oversight committee that was charged with developing refinements to the WCA for consideration in a future proceeding.[204] ICNU's proposed ad hoc adjustments to the WCA are inconsistent with the Commission's order in the 2006 GRC.

74. With respect to Adjustment 3, Mr. Falkenberg claims that the Company's eastern market modeling does not comply with the Commission's order in the 2006 GRC because the Company

---

[199] Falkenberg, TR. 663:5-17.
[200] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 8 ¶ 117-118 (June 21, 2007); Falkenberg, Exh No. RJF-18 30-33.
[201] Falkenberg, TR. 667:16-21.
[202] Duvall, Exh. No. GND-5T 32:16-18.
[203] Duvall Exh. No. GND-5T 34:4-10. *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 8 (June 21, 2007).
[204] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 8 at 13-14 (June 21, 2007).

models only sales from the west to the east, not purchases.[205] The eastern market sale was a Staff adjustment, which the Company accepted. The Company has modeled the eastern market sale in this case precisely as it was modeled in the 2006 GRC.[206] While Mr. Falkenberg focuses on the issue of a purchase from the east, only approximately $48,000 of Mr. Falkenberg's $1 million adjustment results from including purchases from the east to the west. The remainder of the adjustment is due to Mr. Falkenberg's changes to the Commission-approved modeling of sales to the east. Notably, Mr. Falkenberg's modifications include modeling the adjustment outside of GRID,[207] which is contrary to his testimony that GRID should be used to model adjustments where practicable.[208]

75. With respect to Adjustment 4, ICNU severs the links between PACW and PACE which artificially creates a shortage of energy in PACE. ICNU then calculates the resulting imbalance charges and calculates an adjustment to PACE based on the value of the imbalance charges.[209] This $1.2 million adjustment is described in a single paragraph in Mr. Falkenberg's testimony. The most significant of the adjustment's many analytical problems is the fact that when severing the ties between PACE and PACW, Mr. Falkenberg "islands" Colstrip 3 and a portion of Jim Bridger in PACW (even though they are allocated to PACE) and partially cuts off Wyoming from other PACE states by removing the IPC to Path C link. This modeling creates false energy shortages in PACE and undermines the basis of ICNU's adjustment.

2. ICNU's Adjustment to the Colstrip Wheeling Expense is Unreasonable.

76. ICNU proposes that the Commission change the modeling of the Colstrip wheeling

[205] Falkenberg, Exh. No. RJF-1CT 16:1-21.
[206] Falkenberg, TR. 647:9-648:17.
[207] Duvall, Exh. No. GND-5T 35:1-7.
[208] Falkenberg, Exh. No. RJF-8T 3:6-7.
[209] Duvall, Exh. No. GND-5T 35:8-18; Falkenberg, TR. 651:7-657:25.

expense to apportion 45% of the cost to PACW, rather than 50% as modeled by the Company.[210] The Company's even split of the Colstrip wheeling expense is reasonable, especially given the fact that the WCA includes a sale to PACE, which requires transmission capacity.

3. Staff's Adjustment to the Idaho Point-to-Point Contract is Based on an Incorrect Premise and ICNU's Adjustment is an Attempt to Relitigate the WCA Methodology.

77. Staff and ICNU propose an adjustment to expenses related to the Company's point-to-point contract with Idaho Power Company.[211] Staff's adjustment is based on the premise that "[t]he Company appears to be proposing that the Commission should allocate the *entire cost* of the wheeling contract to the West Control Area . . . at a minimum these costs should be split between the West Control Area and the East Control Area, because both control areas benefit from the service provided under the contract."[212] However, as Mr. Falkenberg acknowledged at the hearing, the Company has already removed approximately one-third of the costs associated with the contract from this case, or $1.6 million, because those are resources that serve PACE.[213] Staff's proposed adjustment appears to be based on the incorrect premise that the Company included the entire cost of the contract, when it did not.

78. ICNU's adjustment to the Idaho Point-to-Point contract is based on a different premise. ICNU argues that because the Commission rejected ICNU's proposal to include benefits from the reserve transfers between PACW and PACE associated with this transmission link in the 2006 GRC, it is unreasonable to include the associated costs.[214] The Commission previously rejected ICNU's proposal to impute benefits to PACW for reserves provided to PACE under the Idaho Point-to-Point contract on the basis that "ICNU's imputations of . . . $1.2 million of

---

[210] Falkenberg, Exh. No. RJF-1CT 31:23-24.
[211] Buckley, Exh. No. APB-1CT 20:3-11; Falkenberg, Exh. No. RJF-1CT 32:21-22.
[212] Buckley, Exh. No. APB-1CT 20:13-18 (emphasis added).
[213] Falkenberg, TR. 654:19-24.
[214] Falkenberg, Exh. No. RJF-1CT 32:9-17.

operating reserve benefits are speculative and rely on arbitrage that may not be physically possible."[215] In this case, ICNU is simply proposing the flip side to its prior argument, now arguing that the costs of providing PACE with reserves should be disallowed, rather than arguing that benefits should be imputed to PACW for providing PACE with reserves. The Company has not changed its modeling of the Idaho Point-to-Point contract since the 2006 case, and there is no other basis identified for revisiting this issue.[216]

D. The DC Intertie Contract Is Used and Useful in the Test Year.

79. Staff and ICNU propose removing the costs associated with the DC Intertie agreement from rates on the basis that GRID does not reflect any purchases associated with this contract in the test year and therefore the Company has not demonstrated the benefits of the contract.[217] This proposal should be rejected. First, ICNU witness Mr. Falkenberg conceded that the Company uses the DC Intertie to purchase power.[218] Mr. Duvall testified that the Company uses the line for over 200 transactions a year, or 75,000 MWh, at a rate of $2 per kW-month, which compares favorably to Bonneville Power Administration's capacity charge of $8 per kW-month.[219] The fact that GRID does not include purchases using the DC Intertie contract on a forecast, normalized basis does not mean that such purchases will not occur. Moreover, both Staff and ICNU focus on the energy benefits of the contract and ignore the capacity and diversity benefits of the contract.[220] The costs of the contract are reasonable in light of the benefit to the Company's overall transmission strategy and hedge against changes in the market.[221] Therefore

---

215 *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 8 ¶ 54 (June 21, 2007).
216 Falkenberg, TR. 655:19-23; Duvall, Exh. No. GND-5T:11-16.
217 Falkenberg, Exh. No. RJF-1CT 33:10-11; Buckley, Exh. No. APB-1CT 19:1-8.
218 Falkenberg, TR. 656:10-657:16.
219 Duvall, TR. 304:2-8.
220 Duvall, Exh. No. GND-5T 42:4-15.
221 Duvall, Exh. No. GND-5T 42:13-15.

ICNU's claim that the DC Intertie contract is not used and useful in the test year is incorrect.[222]

80. Second, to the extent that Staff and ICNU allege that the DC Intertie contract is imprudent, the Commission has found in previous cases that a party challenging a contract that could have been challenged years earlier "should raise the issue sooner rather than later when there is an opportunity to do so," and must make a "substantial showing" of imprudence.[223] Staff and ICNU have had an opportunity to challenge the DC Intertie agreement since at least 2003 and have not done so, even during the development of the WCA methodology when the parties reviewed all transmission resources to determine whether they were used and useful.[224] Neither Staff nor ICNU have made a substantial showing that the DC Intertie agreement is imprudent. In fact, Mr. Falkenberg conceded in a proceeding in Idaho that the DC Intertie has been a valuable resource.[225] He also noted that "[t]ransmission capacity in the region is limited and it is hard to imagine that this important link [the DC Intertie contract] has no value."[226]

E. Consistent with the Supremacy Clause, the Commission Should Allow Recovery of Costs Incurred under the Company's OATT.

81. Staff and ICNU propose that the Commission disallow costs associated with integrating non-owned wind plants that the Company is required to incur under its Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariff (OATT).[227] ICNU and Staff acknowledge that the Company actually provides wind integration services to non-owned facilities and that the Company's OATT does not allow the Company to recover the cost of providing wind integration services from these facilities.[228] The issue, then, is whether retail customers should pay the costs associated with integrating non-owned wind facilities that the

---

[222] *See* Falkenberg, Exh. No. RJF-1CT 34:2-5.
[223] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 8 ¶ 122 (June 21, 2007).
[224] Falkenberg, TR. 659:19-661:10.
[225] Falkenberg, TR. 658:23-659:3.
[226] Falkenberg, Exh. No. RJF-20 5:15-16.
[227] Falkenberg, Exh. No. RJF-1CT 46:8-10; Buckley, Exh. No. APB-1CT 24:3-25:5.
[228] Falkenberg, Exh. No. RJF-1CT 46:4-7; Buckley, TR. 592:1-9.

Company is required to integrate pursuant to its OATT.

82. Staff's and ICNU's adjustment violates the Supremacy Clause of the United States Constitution and the filed rate doctrine. FERC has exclusive authority over the transmission and sale of electricity in interstate commerce pursuant to the Federal Power Act.[229] The Supreme Court held in *Nantahala Power and Light Co. v. Thornberg*, 476 U.S. 953 (1986) that by virtue of FERC's supremacy in this arena, "a state utility commission setting retail rates must allow, as reasonable operating expenses, costs incurred as a result of paying a FERC-determined wholesale price . . . Once FERC sets such a rate, a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable."[230] States may not bar utilities "from passing through to retail customers FERC-mandated wholesale rates."[231] The filed rate doctrine also prevents a state from modifying FERC-approved wholesale rates.[232] The filed rate doctrine requires that FERC-approved rates be given binding effect by states.[233]

83. ICNU argues that the Company should have filed with FERC to recover wind integration costs from transmission customers and that customers should not be charged because the Company has not done so.[234] The implication is that PacifiCorp would be able to recover wind integration charges under its OATT if only it had made such a request to FERC. In fact, FERC has rejected several requests by utilities, including Puget to include a wind integration charge in their OATTs.[235] The only wind integration charge proposal accepted by FERC thus far has been a proposal by Westar, which was adopted only as "an interim measure which will be effective

---

[229] 16 U.S.C. § 791 *et seq.*; *Nantahala Power & Light Co. v. Thornberg*, 476 U.S. 953, 963-64 (1986); *Cogeneration Ass'n of Cal. V. Fed. Energy Regulatory Comm'n*, 525 F.3d 1279, 1280 (D.C. App. 2008).
[230] *Nantahala*, 487 U.S. at 372.
[231] *Miss. Power & Light Co. v. Miss.*, 487 U.S. 354, 372 (1988).
[232] *Nantahala*, 487 U.S. at 966. The Company's OATT does not contain an explicit charge for wholesale wind integration rates, so imputing such a charge in PacifiCorp's rates would violate the filed rate doctrine and interfere with FERC's plenary authority over transmission rates in interstate commerce.
[233] *Nantahala*, 487 U.S. at 962.
[234] Falkenberg, Exh. No. RJF-1CT 45:3-12.
[235] Buckley, Exh. No. APB-16 19, n.39; Buckley, TR. 593:18-23..

only until [the Southwest Power Pool, Inc.'s] expected balancing area consolidation and ancillary services market are implemented."[236]

84. In addition, FERC recently issued a notice of proposed rulemaking (NOPR) on the issue.[237] The NOPR lays out the path to begin charging all wind generators, including non-owned facilities, for the costs incurred to integrate them into the Company's balancing areas. Pending any additional guidance from FERC on this issue, the Company believes that it can include a proposal for a new regulation service charge as part of the transmission rate case filing and that such a proposal has a higher chance of being accepted because of this recent guidance.

85. As an alternative to Staff's and ICNU's proposal, the Company proposes the Commission allow the Company to monitor FERC guidance on this issue and include a proposed regulation service charge to integrate wind, in its request for transmission tariff rates in its upcoming rate case if consistent with the direction provided in the NOPR and any future FERC guidance.[238] Such an outcome would be consistent with the approach Oregon and Utah have taken by not adopting an adjustment to costs associated with non-owned wind generation, but allowing the Company to pursue recovering such costs in its OATT before FERC.[239]

F. Staff's and ICNU's Colstrip Outage Adjustments Will Result in Inaccurate Forced Outage Rates.

86. Staff and ICNU propose adjusting the Company's forced outage rate to account for the unplanned outage of 166 days experienced at the Company's Colstrip 4 plant in 2009.[240] Staff

[236] *Westar Energy, Inc.*, Docket No. ER09-1273-000, 130 FERC ¶ 61,215 (Mar. 18, 2010). The Company requests that the Commission take official notice of this order pursuant to WAC 480-07-495(2)(a)(i)(A).
[237] Buckley, Exh. No. APB-16.
[238] *See* Duvall, Exh. No. GND-5T 46:1-4.
[239] *See* Buckley, TR. 597:13-25; *Re. PacifiCorp 2011 Transition Adjustment Mechanism*, Oregon PUC Docket UE 216, Order No. 10-363, Appendix A at 4 (Sept. 16, 2010); *Re. Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah*, Utah PSC Docket 09-035-23, Order at 51 (Feb. 18, 2010). The Company requests that the Commission take official notice of this order pursuant to WAC 480-07-495(2)(a)(i)(A).
[240] Falkenberg, Exh. No. RJF-1CT 50:9-13; Buckley, Exh. No. APB-1CT 17:18-23.

recommends that the extended outage be removed and the outage rate of Colstrip 4 be based on an 8% effective forced outage rate,[241] while ICNU recommends that the outage be capped at 28 days (which produces an even lower forced outage rate).[242] Neither Staff nor ICNU contend that the outage was imprudent. Therefore, the question is whether the forced outage rate proposed by the Company, which includes the Colstrip 4 outage as a part of a four-year average, is a reasonable estimate of the forced outage rate expected in the test year.

87. The adjustments of Staff and ICNU would result in an abnormally low outage rate in the test year.[243] Staff's adjustment is based on an 8% outage rate, which Mr. Buckley states is "conservative when anomalous extended outages are not considered."[244] Removing significant outages from the calculation of forced outages, while keeping unusually low outage periods such as the 174-day period used to calculate the forced outage rate in this case, artificially skews forced outage rates downward.[245] Staff's proposal to remove unusually long, but prudent, forced outages results in a forced outage rate that does not reflect actual experience.[246]

88. Furthermore, while outages of the length experienced at Colstrip are rare, experiencing an unusually high forced outage rate at Colstrip in one year out of a four-year period is not unusual. The Avista testimony relied upon by Mr. Buckley in calculating his adjustment shows that the outage rate at Colstrip exceeds 10% every 3.7 years.[247] While Mr. Falkenberg claims that the Colstrip outage was "an extremely rare event,"[248] he also states that "a one in 4 year event is clearly ordinary."[249] Because experiencing a forced outage rate above 10% in one year out of

---

[241] Buckley, Exh. No. APB-1CT 17:8-12.
[242] Falkenberg, Exh. No. RJF-1CT 50:10.
[243] Duvall, Exh. No. GND-5T 49:13-20.
[244] Buckley, Exh. No. APB-10.
[245] Duvall, Exh. No. GND-5T 50:2-14.
[246] Duvall, Exh. No. GND-5T 50:10-12.
[247] Buckley, Exh. No. APB-13 3:10-12.
[248] Falkenberg, Exh. No. RJF-1CT 50:4.
[249] Falkenberg, Exh. No. RJF-14.

four is "clearly ordinary," there is no basis to adjust the forced outage rate.

89. Finally, the Company requests that the Commission disregard Staff's reliance on the settlement with Avista regarding the removal of anomalous outage rate years.[250] Unlike Avista, PacifiCorp does not have a PCAM in Washington.[251] PacifiCorp therefore has no opportunity to recover if the forced outage rate results in an under recovery of NPC in base rates. If the Commission accepts an adjustment to NPC for the Colstrip outage, the Company requests that the Commission authorize the Company to file for deferral to recover the difference between the actual forced outage rate for Colstrip 4 filed in this case and the adjusted forced outage rate allowed. Staff witness Mr. Buckley stated that Staff would be open to such a deferral to allow PacifiCorp to recover its prudent costs.[252]

G. ICNU's Proposed Disallowance of Derations at the Jim Bridger Plant Ignores that Overall Costs Associated with Bridger Fuel Have Decreased.

90. ICNU proposes to disallow derations at the Jim Bridger plant based on ICNU's position that the fuel quality at the Bridger Plant has resulted in derations.[253] The Bridger plant has experienced a higher level of derations due to increased reliance on coal from the underground mine and limitations on blending of coal.[254]

91. ICNU's proposed adjustment is inappropriate because it ignores the fact that the overall costs at the Bridger mine in NPC have decreased by $3.3 million on a WCA basis due to increased production and efficiency in the underground operation.[255] ICNU's proposed adjustment would unfairly remove the costs associated with "low-quality" coal from the underground mine, but accept the lower costs resulting from the savings that result from the use

[250] *See* Buckley, Exh. No. APB-1CT 16:13-16.
[251] Duvall, Exh. No. GND-5T 50:15-19.
[252] Buckley, TR. 586:8-587:1.
[253] Falkenberg, Exh. No. RJF-1CT 54:11-16.
[254] Duvall, Exh. No. GND-5T 51:17-52:11.
[255] Duvall, Exh. No. GND-1T 7:3-13.

of that coal.[256]

H. ICNU's Planned Outage Schedule is Unreasonable.

92. ICNU proposes that its planned outage schedule be substituted for the one used by Company in modeling planned outages. While the Company accepts ICNU's proposed change to the Colstrip outage schedule,[257] the Company objects to ICNU's proposed change to the Hermiston schedule. ICNU's proposal would move the Hermiston outage from the spring of 2011 to the spring of 2012, when "the economics of running the plant are least attractive."[258] ICNU's proposal is inappropriate because it unreasonably assumes that the Hermiston plant can go without a planned outage in 2011.[259] Also, ICNU's proposal would mean that the Hermiston outage would occur in February and March of 2012, when winter peak loads can occur in the Pacific Northwest, rather than April and May of 2011, during the spring runoff.[260] Finally, the Commission has previously found that it is unreasonable to assume that maintenance is always timed to coincide with the period of lowest wholesale prices.[261] Given that ICNU's proposal is based on timing the maintenance for when the economics of running the plant are least attractive and ignores other variables, the Company requests that the Commission reject this adjustment.

I. The SMUD Delivery Pattern Should Reflect Normalized Data, Consistent with the Treatment of Similar Contracts.

93. Staff and ICNU propose substituting actual data for normalized data for modeling the SMUD call option sales contract.[262] Staff's and ICNU's proposal should be rejected because the parties do not propose deoptimizing all resources and contracts—only the SMUD contract,

[256] Duvall, Exh. No. GND-5T 52:15-21; Duvall, TR. 347:8-15.
[257] Duvall, Exh. No. GND-5T 29:20-22.
[258] Falkenberg, Exh. No. RJF-1CT 48:23-49:1.
[259] Duvall, Exh. No. GND-5T 30:8-9.
[260] Duvall, Exh. No. GND-5T 30:9-11.
[261] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket No. UE-050482, Order 5 at ¶ 101 (Dec. 21, 2005).
[262] Falkenberg, Exh, RJF-1CT 25:14-21; Buckley, Exh. No. APB-1CT 13:6-10.

which results in a decrease to NPC.[263] Optimization of the Company's operations decreases NPC on a net basis.[264] ICNU attempts to justify its selective and one-sided adjustment by arguing that the Company cannot model the loads, constraints, or forward price curves used by SMUD.[265] Given the impossibility of obtaining such data, however, the only reasonable way to model such contracts is to assume the counterparties will act rationally and exercise their rights to lower their costs.[266] ICNU's criticism also ignores the fact that actual market prices that SMUD will be evaluating in the test year will be different from historical prices.[267] This adjustment is an indirect way of disallowing costs associated with the SMUD contract, an adjustment that ICNU proposed and the Commission rejected in the 2006 GRC.[268]

J. ICNU's Minimum Loading and Deration Method Results in Artificial Reductions to NPC.

94. ICNU proposes to alter the Company's method of derating the maximum capacity of generating units, which derates the maximum capacity of the unit in every hour of the year by an equal percent based on historic forced outage rates, and results in a "haircut" in unit availability.[269] Mr. Falkenberg's adjustment is inappropriate because the only time that the derate adjustment is applicable is when a unit is dispatched at its derated maximum capacity; at any level below that, GRID decided to dispatch the unit at a lower and less efficient generation level, whether it had been derated or not.[270] Mr. Duvall's testimony shows that heat input required for various levels of generation is understated using the derate-adjusted heat rate.[271] Mr. Falkenberg's adjustment also reduces the minimum generation level of units below their

---

263 Duvall, Exh. No. GND-5T 36:9-15.
264 Duvall, Exh. No. GND-5T 36:21-22.
265 Falkenberg, Exh, RJF-1CT 28:13-15.
266 Duvall, Exh. No. GND-5T 37:13-21.
267 Duvall, Exh. No. GND-5T 38:1-8.
268 *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 8 ¶ 124 (June 21, 2007).
269 Duvall, Exh. No. GND-5T 53:7-10; Falkenberg, Exh. No. RJF-1CT 55:1-15.
270 Duvall, Exh. No. GND-5T 53:17-54:3.
271 Duvall, Exh. No. GND-5T 54:4-13; Exh, GND-10; Exh. No. GND-11.

technical capability, which artificially increases the operating range of each unit.[272] ICNU's minimum loading and deration adjustment artificially reduces NPC.

K. Additional Adjustments Accepted by the Parties.

95. In Mr. Duvall's rebuttal testimony, he outlined the NPC adjustments accepted by the Company in whole and in part.[273] The Company believes that the adjustments it has accepted in part represent reasonable compromises of the issues raised by Staff and ICNU. To the extent those parties disagree and continue to contest the adjustments that the Company accepted in part, the Company will address those adjustments in its reply brief.

96. Since the Company's rebuttal testimony, additional NPC adjustments have been resolved as follows:

- Update to Chehalis reserves: As described in the Company's Response to Bench Request 3, the Company has agreed to remove the Chehalis reserve update.
- SCL Stateline: As described and qualified in the Company's Response to Bench Request 3, in return for the Company's agreement on the Chehalis reserves, Staff and ICNU have agreed to support the Company's treatment of Seattle City Light Stateline as contained in the rebuttal testimony of Mr. Duvall.
- Staff, the Company, and ICNU agree to update NPC for the December 2010 official forward curve.
- Start-up O&M: Based on Mr. Falkenberg's admission at the hearing that the Company did not include incremental O&M start up costs in its filing, the Company believes that ICNU's proposed adjustment to remove such costs is resolved.[274]

[272] Duvall, Exh. No. GND-5T 55:1-6.
[273] Duvall, Exh. No. GND-5T 22:2-30:19.
[274] Falkenberg, TR. 673:10-14.

VI. TAX ISSUES

A. Full Normalization Benefits Customers and is Good Policy.

97. Staff objected to the Company's proposal to move to full normalization of income taxes because Staff maintained that it is the "Commission's long-standing policy to use flow-through when it is lawful to do so."[275] Staff cited four Commission orders from the 1980's and one from the 1990's to support this contention.[276] Staff witness Ms. Kathryn Breda's testimony also identifies three orders from 1994, 2004, and 2005 where the Commission explicitly authorized the use of normalized accounting, acknowledging that: "The Commission has approved normalization for many single issues."[277] In response to a Company data request, Ms. Breda identified 14 additional Commission orders authorizing normalized accounting.[278] Almost all of these orders post-date the flow-through orders Ms. Breda relied upon, suggesting that the Commission's policy is moving towards full normalization.

98. While offering no policy arguments in support of flow-through accounting,[279] Ms. Breda's testimony admitted that normalization is more consistent with sound ratemaking principles and "upholds the matching principle and provides for intergenerational equity."[280] Normalizing "matches tax benefits with cost responsibility and prevents customers who pay for the cost of an asset well past its tax life from paying a disproportionately higher tax rate than customers that pay for the same asset during its tax life."[281]

99. Staff's support of the Company's proposal to normalize the repairs deduction also points to another important customer benefit provided by normalization—the selection of the test year

---

[275] Breda, Exh. No. KHB-1T 7:12-13. The orders cited were from 1984, 1985, 1986, 1983, and 1997.
[276] Breda, Exh. No. KHB-1T 7:12-21.
[277] Breda, Exh. No. KHB-1T 8:8-14; Breda, Exh. No. KHB-1T 24:21.
[278] Fuller, Exh. No. RF-9 1-2.
[279] Breda, Exh. No. KHB -1T 5:4-13; 8:1-4; Fuller, Exh. No. RF-8T 5:19-6:8
[280] Breda, Exh. No. KHB-1T 4:19-22; Fuller, Exh. No. RF-1T 6:23-7:6.
[281] Fuller, Exh. No. RF-1T 6:23-7:6.

does not determine the extent, if any, of customer benefit resulting from a "significant reduction in taxes payable."[282] Ms. Breda correctly testified that under flow-through accounting "ratepayers could lose the rate impact of tax benefits" that occur outside the test period and that the flow-through method "may cause fluctuations in taxes reflected in cost of service for ratemaking purposes."[283] Under flow-through accounting, customers would have permanently lost the repairs deduction's Washington-allocated tax benefits of $25.3 million because these benefits would have been outside the test period.[284] In this case, the Company proposed to avoid the harsh outcome of flow-through accounting by volunteering to treat the repairs deduction as a normalized item.[285] There is little policy justification for accepting this approach for items with large revenue impacts such as the repairs deduction, while rejecting normalization for other book-tax differences.

100. Authorizing full normalization in this case would create a clear and unambiguous policy, which is important to PacifiCorp, its regulators, its auditors, and its customers.[286] A general policy of flow-through accounting with selective or even implicit authorization to use normalized accounting creates huge regulatory and accounting uncertainty, especially because the Company must account for its book-tax differences well prior to filing a general rate case.[287] Even Staff appears unclear as to when and to what extent Washington's utilities currently use normalized accounting.[288] At hearing Ms. Breda testified that "it's difficult to come up with a list [of orders

---

[282] Breda, Exh. No. KHB-1T 15:1-11, 24:10-13.
[283] Breda, Exh. No. KHB-1T 7:3-6; 24:14-16; Breda, Exh. No. KHB-1T 6:22-7:1.
[284] Fuller, Exh. No. RF-8T 12:1-13.
[285] Breda, Exh. No. KHB-1T 15:8-11; 24:17-20.
[286] *Wash. Utils. & Transp. Comm'n v Puget Sound Energy,* Docket UE-090704, Order 11 at ¶ 32 (Apr. 2, 2010) (to improve the "quality of the record" the Commission provided "some parameters for future guidance to parties").
[287] Fuller, Exh. No. RF-1T 8:2-7; Fuller, Exh. No. RF-8T 6:16-7:7.
[288] Fuller, Exh. No. RF-9 ("it is difficult to discern what specific accounting treatment is implied without examining the underlying record in the docket"), Breda, TR. 752:18-20 ("it's difficult to find an order that speaks specifically to tax normalization").

authorizing normalization] because it's not always discussed."[289]

101. This case represents an excellent opportunity for the Commission to authorize a move to full normalization with minimal customer impact.[290] The Company's evidence demonstrated that a move to full normalization actually *reduces* the test year revenue requirement and the flow-through effects from past periods will have no net effect on customers under the Company's proposal.[291] Thus, in this case and with this test period, the Commission can capture all of the benefits of normalization identified above without negative consequences.[292]

B. Staff's Adjustment to Remove Full Normalization is Flawed.

102. Staff's proposed adjustment to remove full normalization resulted in a decrease to the overall revenue requirement of $1.9 million.[293] The Company's analysis, on the other hand, reflects that the removal of full normalization results in an *increase* of $6,000.[294] The difference is due to Ms. Breda's conclusion that the Commission implicitly authorized normalized treatment for five particular book-tax differences and therefore the Company's analysis that applied the flow-through method to these items is wrong.[295] This analysis is flawed because (1) when the Commission authorizes normalization it does so explicitly and (2) the Commission has not explicitly authorized normalization for any of these five items.

103. When asked to "provide a comprehensive list" of orders where the Commission authorized normalized treatment, Staff produced a list of fourteen different orders.[296] Ms. Breda

[289] Breda, TR. 756:1-3.
[290] Fuller, Exh. No. RF-8T 4:15-20.
[291] Fuller, Exh. No. RF-8T 4:9-14.
[292] Fuller, Exh. No. RF-8T 4:15-20.
[293] Breda, Exh. No. KHB-1T 23:13-15.
[294] Fuller, Exh. No. RF-8T 1:13-16.
[295] *See* Fuller, Exh. No. RF-15 (reconciling Fuller, Exh. No. RF-12 and Breda, Exh. No. KHB-6); Breda, TR. 749:12-750:15 (her adjustment moves these items from flow-through to normalized); Breda, TR. 752:2-14 (the difference between Staff and the Company is that Ms. Breda normalized these five assets because regulatory assets are "usually" normalized).
[296] Fuller, Exh. No. RF-9.

testified that these were orders where the Commission made "specific reference" to normalization.[297] Coupled with the orders identified in Ms. Breda's testimony that explicitly authorized normalization,[298] it is apparent that when approving normalization, the Commission's orders historically have been clear and explicit, which is crucial under a policy where normalization is an exception to the general policy of flow-through accounting.

104. Importantly, none of the five items Staff now claims must be normalized were included in the either Mr. Breda's testimony or Staff's data request response identifying instances where the Commission authorized normalization.[299] Staff's adjustment is based on its conclusion that the Commission authorized normalization of these items even though Staff can point to no order that actually did so. Indeed, one item, the Medicare Deferred Tax Expense, is new in this case and has never been the subject of any Commission order. It is difficult to understand how the Commission could have implicitly authorized normalized accounting for this item as Staff now claims. At hearing Ms. Breda explained this inconsistency stating that this item was normalized *in this case* and "it's an uncontested item."[300] However, in discovery Staff indicated that it was not proposing normalization for anything except the repairs deduction.[301] Further, despite Ms. Breda's assertion, this does represent a contested item. The Company has proposed comprehensive normalization, not normalization on a case-by-case basis.

105. The largest of the disputed items relates to the Chehalis Generating Plant (Chehalis),

[297] Breda, TR. 755:18-756:3. Ms. Breda's testimony with respect to this issue is problematic because she also testified that "most of the time" when the Commission authorizes a deferral it also authorizes normalization and that "there are some specific instances" where the Commission has done otherwise. Breda, TR. 755:13-17. This leaves the impression that unless the Commission specifically says otherwise, normalization is authorized when the Commission allows a deferral. Staff's own testimony and the Commission orders cited therein contradict this statement.

[298] Breda, Exh. No. KHB-1T 8:6-14.

[299] Breda, TR. 756:4-8.

[300] Breda, TR. 757:6-14.

[301] Fuller, Exh. No. RF-8T 9:17-22; Fuller, Exh. No. RF-10.

which Ms. Breda concludes must be normalized because it is a regulatory asset.[302] The Commission's order amortizing that deferral does not explicitly state that the book-tax difference related to that asset should be normalized.[303] While the Commission has on numerous occasions expressly authorized normalization related to deferrals,[304] it did not do so with respect to Chehalis and therefore Staff's current position that normalization was "implied" is without support.[305] Ms. Breda testified at hearing that the Commission "usually" authorizes normalization for deferrals and that "most of the time" the Commission authorizes normalization if there are taxes included in a deferral.[306] Ms. Breda could point to nothing other than these general statements to support her conclusion that the Commission authorized normalized accounting of the Chehalis deferral or any of the other four items.[307]

106. Because Staff acknowledges that no Commission order explicitly authorized normalization treatment for these five items, Ms. Breda explained at hearing how one must go about determining whether normalization was implied. To do so, Ms. Breda explained, one must look at the record in the underlying docket and determine if the company proposed normalization and if it was a contested item.[308] With respect to all of the five items, and Chehalis in particular, the issue of income tax normalization was never raised, let alone contested, and the Company never understood the Commission to have authorized normalized accounting treatment for the asset because there are no instructions to that effect.[309] If Staff's analysis is correct, then this is further evidence that the current policy is unclear and creates substantial regulatory and accounting uncertainty.

---

[302] *See* Fuller, Exh. No. RF-15; Breda, TR. 751:4-16.
[303] *Wash. Utils. & Transp. Comm'n v. PacifiCorp* , Docket UE-090205, Order 09 (Dec. 16, 2009).
[304] *See* Fuller, Exh. No. RF-9.
[305] Breda, TR. 755:18-23 (admits there is no Chehalis order authorizing normalization).
[306] Breda, TR. 752:5-14; Breda, TR. 755:6-17.
[307] Breda, TR. 754:2-16 (Ms. Breda could not state that the Commission explicitly authorized normalization).
[308] Breda, TR. 756:19-757:1.
[309] *See* Fuller, Exh. No. RF-15.

C. Staff's Repairs Deduction Adjustment Is Incorrect.

107. Staff's repairs deduction adjustment improperly proposed an additional $14.46 million rate base reduction by annualizing the impact of the repairs deduction over the entire test period even though it was not reflected until September, 2009. There is no basis for selectively annualizing this rate base item and none other in this case.

108. As Ms. Breda acknowledged, the Company's actual accumulated deferred income tax balances did not reflect the repairs deduction until the tax impact occurred in September of 2009.[310] Despite this fact, Staff proposed to calculate rate base as if the repairs deduction was in place for the entire 2009 test period. In essence, Staff proposed to measure rate base at the end of the test period. The Commission noted that "except in rare circumstances rate base is measured as an average over the test year" because an end-of-period measurement "would disrupt test period matching of rate base with other costs, revenues and cost of service components."[311] Staff provided no justification for the Commission to depart from this policy and therefore annualizing the rate base deduction is improper.

109. At hearing, Ms. Breda argued that her adjustment is actually a prior year adjustment and therefore appropriate.[312] In Puget's 2009 rate case, a similar repairs deduction adjustment was rejected by the Commission.[313] There, the test period was 2008 and, like here, the "IRS granted permission for the accounting method in late 2009."[314] Among other reasons, the Commission rejected the proposed adjustment in the Puget case because, "the tax impact is . . . subsequent to the test-year."[315] In this case, as in the Puget case, which presented identical facts, the tax impact

---

[310] Breda, Exh. No. KHB-1T 25:4-7; Breda, TR. 758:6-14; Fuller, Exh. No. RF-8T 12:17-13:2.
[311] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-090134, Order 10 at ¶76 (Dec. 22, 2009).
[312] Breda, TR. 760:7-12; Breda, Exh. No. KHB-1T 25:2-11.
[313] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at ¶¶ 195-197 (Apr. 2, 2010).
[314] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at ¶ 193 (Apr. 2, 2010).
[315] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at ¶ 197 (Apr. 2, 2010).

of the repairs deduction occurred with the change in accounting method, which here Staff admits occurred in September, 2009.[316] This is during the test year, not the year prior.

D. The Company's Request for a Regulatory Asset or Liability is Reasonable

110. The Company made a limited and balanced proposal for the establishment of a regulatory asset or liability with respect to interest that may be paid to or received from the Internal Revenue Service (IRS) associated with the repairs deduction.[317] This proposal is reasonable because the Commission has already determined that there is a demonstrated risk of recognizing allowed accounting changes before they are audited by the IRS.[318] In the alternative, the Company requests that the Commission apply the same regulatory treatment afforded to Puget in its most recent general rate case, and delay reflecting the tax benefits of the repairs deduction in rates until the IRS has made a final tax determination with respect to this deduction.[319]

VII. OTHER REVENUE REQUIREMENT ADJUSTMENTS

A. Cash Working Capital (CWC)

1. ICNU/Public Counsel's Adjustments Have No Merit.

111. Mr. Meyer's adjustment removed all CWC from the Company's rate base because he concluded that had the Company performed a lead-lag study, the outcome of that study would have resulted in a negative CWC.[320] Mr. Meyer did not perform such a study and relied instead on anecdotal accounts from his experience with the Missouri Public Service Commission.[321] The Commission has made clear that parties proposing changes to the Company's CWC methodology must "provide full evidentiary support of any proposals and methods they may

[316] Breda, TR. 761:4-10.
[317] Fuller, Exh. No. RF-1T 5:3-16; Fuller, Exh. No. RF-8T 13:9-14:12.
[318] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at ¶ 195 (Apr. 2, 2010).
[319] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-090704, Order 11 at ¶ 197 (Apr. 2, 2010).
[320] Meyer, Exh. No. GRM-1T 4:3-8.
[321] Meyer, Exh. No. GRM-1T 4:3-8.

submit to substantiate adjustments to a company's figures."[322] Mr. Meyer's proposal falls well short of the Commission's standards and should be rejected.

2. Staff's Adjustment is Inconsistent with Commission Precedent.

112. Staff's CWC adjustment removes all CWC, fuel stock, and materials and supplies balances on the basis of the Investor Supplied Working Capital (ISWC) method.[323] The Commission should reject this adjustment because the ISWC method used here has the same flaws that lead to its rejection by the Commission in the Company's 2006 rate case. In that case, the Commission rejected Staff's ISWC method because it was not performed "in a manner consistent with the WCA allocation methodology."[324] During the hearing in the 2006 case, Commissioner Oshie asked Mr. Schooley:

> Q:. . . when you did your analysis of the [ISWC] that formed the basis of your recommendation in this case . . . did you do the analysis based upon a Western Control Area and Eastern Control Area scenario or did you do a total company analysis and then allocate a percentage of the total company to Washington?
>
> A: I did not look at divvying up of the resources or the rate base between control areas. I did do it on a total company basis and, in the end applied the system operations factor . . .[325]

113. The Commission rejected Staff's method because it was performed "on a total company basis, not a WCA basis," and then allocated to Washington "based on Washington plant relative to total system plant."[326] Here, Mr. Schooley's analysis is fundamentally identical to his analysis in the 2006 rate case because he once again calculated CWC on a total Company basis.[327]

114. When Mr. Schooley described his method in this case, he stated that his analysis "is

---

[322] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04 ¶ 188 (Apr. 17. 2006).
[323] Schooley, Exh. No. TES-1T 26:20-27:6.
[324] *Wash. Utils. & Transp. Comm'n v.PacifiCorp*, Docket UE-061546, Order 08 at ¶ 162 (June 21, 2007).
[325] Docket UE-061546, TR. 318:19-319:4. The Company requests that the Commission take official notice of the transcript filed in this docket pursuant to WAC 480-07-495(2)(a)(i).
[326] *Wash. Utils. & Transp. Comm'n v.PacifiCorp*, Docket UE-061546, Order 08 ¶ 162 (June 21, 2007).
[327] Dalley, Exh. No. RBD-4T 13:19-14:8.

based on PacifiCorp's *total company* balance sheet for the year ending December 31, 2009."[328] In his 2006 testimony, his analysis was based upon "PacifiCorp's *total company* balance sheet as of March 31, 2006."[329] Here, using the total company balance sheet, Mr. Schooley concluded that investors supplied no working capital because the *total company investments* exceeded the *total company invested capital.*[330] In 2006, Mr. Schooley calculated his CWC by "subtracting the *total investments* from the *total invested capital.*"[331] Indeed, the only substantive difference between the method used here and the method the Commission rejected in 2006 involved the calculation of the factor used to allocate CWC to Washington.[332]

115. Staff's proposed adjustment to fuel stock and materials and supplies should likewise be rejected. These materials are essential to Company operations, ensure it can provide reliable service to customers, and are recoverable in all other jurisdictions.[333] Moreover, Staff's analysis lacks evidentiary support and was calculated in the same improper manner as the CWC.[334]

3. The Company's CWC Method Is Consistent With WCA Methodology and a Generally Accepted Method for Calculating CWC.

116. The Company's 45-day method is consistent with Commission precedent because it is well supported in the record and conforms to the Commission-approved WCA allocation method.[335] Although the lead-lag method is the Company's preferred method, the Company was concerned about designing such a study consistent with the Commission's order in the 2006 rate

[328] Schooley, Exh. No. TES-1T 14:4-5 (emphasis added).
[329] Docket UE-061546, Schooley, Exh. No. TES-1T 17:2-4 (emphasis added). The Company requests that the Commission take official notice of Mr. Schooley's testimony filed in this docket pursuant to WAC 480-07-495(2)(a)(i).
[330] Schooley, Exh. No. TES-1T 14:15-18 (emphasis added).
[331] Docket UE-061546, Schooley, Exh. No. TES-1T 17:9-11 (emphasis added).
[332] Schooley, Exh. No. TES-1T 18:4-19:12; Dalley, Exh. No. RBD-4T 15:12-19.. In this case, because Mr. Schooley concluded that the CWC was zero, he did not actually allocate CWC to Washington. However, his testimony describes in detail how he would have done so if the CWC value had been positive.
[333] Dalley, Exh. No. RBD-4T 16:18-21, 17:17-23.
[334] Dalley, Exh. No. RBD-4T 17:4-14.
[335] Dalley, Exh. No. RBD-4T 12:5-10.

case and the WCA allocation methodology.[336] Therefore, instead, the Company adopted the 45-day methodology because it is a generally accepted method to calculate CWC,[337] it is fully supported in the record,[338] and it can be performed in a manner consistent with the WCA allocation method.[339] This method uses Washington-specific normalized results of operations and is therefore in full compliance with the WCA method.[340]

117. Although Staff's testimony did not challenge whether the Company's method conformed to the WCA method,[341] at hearing Staff raised this issue by suggesting that the Company's allocation method used system-wide allocation factors.[342] As described by Mr. Dalley at hearing, the Company's method is entirely consistent with the WCA allocation method because even the WCA method relies upon system-wide factors for certain pieces.[343] Therefore, simply pointing to the use of system-wide allocation factors does not demonstrate the allocation conflicts with the WCA method.

B. Wage and Salary Adjustments

1. The Company's Incentive Compensation Program is Consistent with Commission Precedent and Results in Market Average Compensation.

118. ICNU/Public Counsel recommend that the portion of compensation designated as incentive compensation be reduced by half.[344] The Company has developed its method of determining compensation based on two fundamental principles. First, market level

---

[336] Dalley, TR. 362:4-7.
[337] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 08 ¶ 160 (June 21, 2007); Dalley, Exh. No. RBD-4T 12:5-10; Dalley Exh. No. RBD-1T 21:8-17.
[338] Dalley, Exh. No. RBD-1T 20:14-21:17.
[339] Dalley, Exh. No. RBD-4T 15:5-8.
[340] Dalley, Exh. No. RBD-4T 15:5-8.
[341] Dalley, Exh. No. RBD-4T 18:1-6.
[342] Dalley, TR. 356:3-359:25.
[343] Dalley, TR. 359:2-8; 359:21-25.
[344] Meyer, Exh. No. GRM-1CT 9:16-19.

compensation is necessary to attract and retain qualified employees.[345] Second, in order to encourage superior performance, compensation is structured such that some portion is "at risk."[346] Combined, base pay and the "target" level incentive element equal the market average for the employee's position. When performance is below expected levels, the employee will receive incentive below target level or no incentive pay and therefore below-average pay.

119. To determine the total cash compensation package for each position, at least annually the Company collects market data for comparable jobs using a variety of compensation studies and calculates the average total cash compensation.[347] The Company then determines the portion of that compensation that will constitute the "at-risk" portion, which is the "target" incentive pay based on a review of market compensation using compensation studies.[348]

120. To determine an employee's incentive pay, the employee's performance is compared against the individual and group goals set for each employee at the beginning of the year.[349] Individual goals account for approximately 70% of an employee's evaluation, while group goals account for approximately 30%.[350] All goals promote the efficient operations of the Company, and focus on safety, reliability, and customer service, thereby providing direct benefits to the Company's customers.[351] No goals relate to financial results, except for those for the executive incentive plan for which the Company has not requested recovery.[352]

121. ICNU/Public Counsel witness Mr. Meyer argues that the goals relate to normal job performance, are not quantitative, and provide shareholder value.[353] This argument actually

---

[345] Wilson, Exh. No. EDW-1T 2:19-3:6.
[346] Wilson, Exh. No. EDW-1T 3:7-9.
[347] Wilson, Exh. No. EDW-1T 3:16-4:3.
[348] Wilson, Exh. No. EDW-1T 4:4-8.
[349] Wilson, Exh. No. EDW-1T 5:20-7:20.
[350] Wilson, Exh. No. EDW-1T 7:2-4, 11-13.
[351] Wilson, Exh. No. EDW-1T 9:9-13.
[352] Wilson, Exh. No. EDW-1T 7:21-8:5.
[353] Meyer, Exh. No. GRM-1CT 9:20-25, 14:18-22.

supports the Company's position—because incentive compensation is an integral part of the market compensation set by the Company, goals *should* relate to normal job performance.[354] As for Mr. Meyer's criticism that the goals are not quantitative, Mr. Wilson explained that not all goals that motivate employee behavior that will provide benefits to customers are quantifiable.[355] Mr. Meyer's criticism that the Company's goals provide shareholder value is incorrect and does not reflect the Commission's precedent on incentive compensation. The only goals that Mr. Meyer cites as examples of goals that provide shareholder value are "Customer Focus" and "Productivity."[356] These goals both explicitly cite benefits to customers.[357] Finally, Mr. Meyer's testimony relates only to group goals, which constitute 30% of an employee's overall evaluation.[358] Even if Mr. Meyer's criticisms were accurate, they do not provide sufficient basis for a 50% disallowance.[359]

122. Undermining all of his testimony is Mr. Meyer's admission that he does not know how the Company structures its incentive compensation.[360] The Commission should discount Mr. Meyer's testimony, as he is admittedly not knowledgeable about the Company's compensation structure.

123. In the Company's most recent fully litigated rate case, the Commission rejected ICNU's proposed disallowance of incentive compensation, finding that the objectives of the incentive

---

[354] Wilson, Exh. No. EDW-3T 10:1-14.
[355] Wilson, Exh. No. EDW-3T 9:10-12.
[356] Meyer, Exh. No. GRM-1CT 14:18-15:5.
[357] Meyer, Exh. No. GRM-1CT 14:18-15:5. Moreover, the Commission has never disallowed incentive compensation on the basis that goals that provide direct benefits to customers provide indirect benefits to shareholders. In fact, in the order cited by Mr. Meyer to support his position on incentive plans, the Commission stated that the utility in that case could "do a far better job in the future of creating incentives and setting goals that advantage ratepayers as well as shareholders." *Wash. Utils. & Transp. Comm'n v. Wash. Natural Gas Co.*, Docket No. UG-920840, Fourth Suppl. Order at 19 (Sept. 27, 1993).
[358] Wilson, Exh. No. EDW-3T 11:3-8; Meyer, TR. 496:12-24..
[359] Wilson, Exh. No. EDW-3T 11:9-11.
[360] Meyer, TR. 495:17-19.

program were related primarily to operational effectiveness, customer satisfaction, and safety.[361] The Company requests that the Commission again find that the Company's incentive compensation plan is reasonable as it is consistent with the plan approved in the 2006 case.

2. The ICNU/Public Counsel Adjustment to the 2009 Wage Increase is Unreasonable and Inconsistent with Commission Precedent.

124. ICNU/Public Counsel proposes to decrease the wage increase actually experienced by the Officer/Exempt labor group from 3.5% to the average increase granted to other labor groups, including union groups.[362] Mr. Meyer's proposal is based on his belief that PacifiCorp did not provide adequate justification that "this labor group should receive one of the highest wage increases for 2009."[363] He also cites other utilities that did not grant wage increases to their executives in 2009 and 2010.[364]

125. Mr. Meyer's proposal to remove the known and measurable wage increases that occurred in 2009 is without merit. As shown in Mr. Meyer's testimony, both Officer/Exempt and Non-Exempt employees received a 3.5% wage increase in 2009; only the union groups received a lower increase.[365] It is unreasonable to rely on union wage increases to calculate non-union wage increases, because the negotiated agreements with union employees may offset more expensive benefits with lower wage increases.[366] The 3.5% increase for non-union employees was less than the average increase in the market assessment conducted by the Company in evaluating its compensation and does not result in above-market compensation.[367] The Commission previously rejected a similar adjustment proposed by Public Counsel in Avista's

[361] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 8 at ¶¶ 184-85 (June 21, 2007).
[362] Meyer, Exh. No. GRM-1CT 29:7-10.
[363] Meyer, Exh. No. GRM-1CT 31:6-7.
[364] Meyer, Exh. No. GRM-1CT 31:10-32:31.
[365] Meyer, Exh. No. GRM-1CT 30 Table 5.
[366] Wilson, Exh. No. EDW-3T 12:14-13:4.
[367] Wilson, Exh. No. EDW-3T 13:18-14:7.

2009 rate case and there is no basis in this case to depart from that precedent.[368]

3. The 2010 Wage Increase Is a Limited Known and Measurable Adjustment.

126. ICNU and Public Counsel also propose to eliminate the entire 2010 wage increase included in the case.[369] The Company included only known and measurable wage increases that occurred in 2010—contract agreements to escalate union labor group wages and the increase to non-union and exempt wages that occurred in January, 2010.[370] Without proposing offsetting adjustments, Mr. Meyer argues that these known and measurable increases should not be included because decreases in other cost elements could offset the 2010 wage increases.[371]

127. Mr. Meyer's argument is inconsistent with Commission precedent on known and measurable adjustments. In Avista's 2009 rate case, Staff and Public Counsel generally agreed "that known and measurable company obligations, such as union wage increases resulting from collective bargaining agreements or non-union wage increases approved by the board of directors, are proper adjustments."[372] The Commission approved such known and measurable increases.[373] The 2010 increases proposed by PacifiCorp in this case are no different—they have either already occurred or are fixed by collective bargaining agreement.[374]

4. There is No Basis to Disallow Employee Costs at the Bridger Plant.

128. In addition to Mr. Falkenberg's proposed adjustment to NPC based on fuel quality derations at the Bridger Plant, Mr. Falkenberg also proposes to remove management bonuses, employee meals and gifts, and donations associated with the Bridger Plant for the same

---

[368] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-090134, Order 10 ¶ 111 (Dec. 22, 2009).
[369] Meyer, Exh. No. GRM-1CT 22:1-3.
[370] Dalley, Exh. No. RBD-1T 10:21-23.
[371] Meyer, Exh. No. GRM-1CT 24:3-7; 25:6-11.
[372] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-090134, Order 10 ¶ 105 (Dec. 22, 2009).
[373] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-090134, Order 10 ¶ 110 (Dec. 22, 2009).
[374] Dalley, Exh. No. RBD-1T 10:21-23.

reason.[375] As discussed above, Mr. Duvall testified that overall costs at the Bridger Mine have decreased by $3.3 million due to increased production and efficiency in the underground operation, so ICNU's proposed adjustment lacks support.[376]

C. The MEHC Management Fee Reflects Benefits Provided to Washington Customers and is Consistent with MEHC's Commitments to Washington.

129. ICNU/Public Counsel propose disallowing expenses in the MidAmerican Energy Holdings Company (MEHC) fee related to MEHC and MidAmerican Energy Company (MEC) bonuses. Company witness Mr. Stuver testified, the Company's participation in the MEHC inter-company affiliated services agreement (IASA) provides benefits to the Company's customers by allowing the Company to receive services that lower the Company's costs overall.[377] For example, the cost of CEO Greg Abel to Washington customers is $102,000, a relatively low amount for a CEO with Mr. Abel's expertise in the energy industry.[378]

130. ICNU/Public Counsel's proposal to remove MEHC and MEC incentive compensation is based on a page from PacifiCorp's Form 10-k and two pages from MEHC's 10-k.[379] Neither of these documents supports Mr. Meyer's adjustment. Not only is the PacifiCorp 10-k applicable only to PacifiCorp incentive compensation, not MEHC incentive compensation, but the page cited by Mr. Meyer relates to the Long Term Incentive Program (LTIP), which is not included in rates.[380] The MEHC 10-k shows that MEHC incentive compensation is based on "customer service, operational excellence, financial strength, employee commitment and safety, environmental respect and regulatory integrity."[381] Such measures provide customer benefits

---

375 Falkenberg, Exh. No. RJF-1CT 54:17-24.
376 Duvall, Exh. No. GND-1T 7:3-13.
377 Stuver, Exh. No. DKS-1T 5:3-6:15.
378 *See* Stuver, TR. 435:13-436:8; Stuver, Exh. No. DKS-3.
379 Meyer, Exh. No. GRM-1CT 36:3-18; Meyer, Exh. No. GRM-7; Meyer, Exh. No. GRM-8.
380 Meyer, Exh. No. GRM-7.
381 Meyer, Exh. No. GRM-8 2.

and are consistent with the Commission's standards for approving incentive compensation.[382]

131. Mr. Meyer questions how adjustments to the management fee are calculated in light of the MEHC commitment 4(b)(i) established in Docket UE-051090 that functions to limit the management fee to $7.3 million on a total-Company basis.[383] As Mr. Dalley explained at the hearing, while MEHC invoiced PacifiCorp approximately $11.5 million for the management fee,[384] only $8.3 million was booked by the Company due to MEHC commitments in another state.[385] To comply with the MEHC commitment in Washington, the Company then reduced that amount to $7.3 million.[386] However, because the Company's rebuttal position resulted in $7.1 million of MEHC management fees included in rates—less than the $7.3 million cap—no further adjustment was required to comply with the MEHC commitment.[387]

D. The Existing Allocation of Outside Legal Expenses Should be Changed Only in a Wider Review of WCA Allocation Factors.

132. ICNU/Public Counsel propose an adjustment to legal expenses on the basis of changing the allocation of legal expenses from the methodology set forth in the Company's WCA allocation handbook to a methodology in which legal expenses that can be allocated on a situs basis are allocated in that manner.[388] Staff witness Mr. Foisy also identifies cost categories in the Company's administrative and general expense accounts that are being allocated to Washington

---

[382] *See Wash. Utils. & Transp. Comm'n v. Wash. Natural Gas Co.*, Docket No. UG-920840, Fourth Suppl. Order at 19 (Sept. 27, 1993) ("Such goals might include controlling costs, promoting energy efficiency, providing good customer service, and promoting safety.").

[383] Meyer, Exh. No. GRM-1CT 1-10. The commitment states that "MEHC and PacifiCorp will hold customers harmless for increases in costs retained by PacifiCorp that were previously assigned to affiliates relating to management fees . . . This commitment is offsettable to the extent PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case the following: i) Corporate allocations from MEHC to PacifiCorp included in PacifiCorp's rates are less than $7.3 million. *Re Application of MidAmerican Energy Holdings Co. and PacifiCorp for an Order Authorizing Proposed Transaction*, Docket UE-051090, Order 8, Appendix A at 13 (Mar. 10, 2006).

[384] Mr. Meyer agreed that the Company provided the invoiced amount to parties. Meyer, TR. 517:11-20.

[385] Dalley, TR. 373:11-374:2.

[386] Dalley, TR. 373:20-22.

[387] Dalley, TR. 373:24-374:2.

[388] Meyer, Exh. No. GRM-1CT 26:10-18; Dalley, Exh. No. RBD-4T 16-21.

customers on a system basis rather than being directly assigned to specific states.[389]

133. The Company requests that the Commission reject ICNU/Public Counsel's selective proposal to situs-assign certain legal expenses. As Mr. Foisy testified, situs assigning some cost categories could increase revenue requirement.[390] The Company supports Mr. Foisy's proposal that the parties discuss ways to refine the allocation assignment of accounts on an overall basis in accordance with the WCA methodology.

VIII. RATE SPREAD AND RATE DESIGN

A. Staff's Rate Spread Proposal is Reasonable and Should Be Adopted.

134. In his rebuttal testimony, Company witness Mr. Griffith explained that, based on the revised revenue increase, the Company proposes to apply the increase consistent with the rate spread methodology recommended by Staff witness Mr. Schooley.[391] The revised rate spread proposal better reflects cost of service results and applies smaller increases to rate schedule classes that are currently paying more than the cost to serve them.[392] The other major rate schedules would receive a uniform percentage increase.[393] The proposed rate spread will result in all major rate schedule classes receiving increases that are less than those originally proposed by the Company, while making progress toward reflecting the cost of service results.[394]

B. The Company's Proposed Residential Basic Charge Increase is Appropriate.

135. The Company proposes an increase in the monthly residential basic charge from $6.00 to $8.50 per month, a reduction from the $9.00 level originally proposed by the Company.[395] The Company proposes to retain the existing inverted residential rate structure for energy charges and

[389] Foisy, Exh. No. MDF-1CT 16:20-17:2; Dalley, Exh. No. RBD-4T 21:9-15.
[390] Foisy, Exh. No. MDF-1CT 19:3-5.
[391] Griffith, Exh. No. WRG-7T 2:8-13.
[392] Griffith, Exh. No. WRG-7T 2:14-17.
[393] Griffith, Exh. No. WRG-7T 2:17-18.
[394] Griffith, Exh. No. WRG-7T 3:2-5.
[395] Griffith, Exh. No. WRG-7T 3:8-13.

apply an approximately uniform percentage increase to the two kilowatt-hour blocks.[396]

136. The Company's proposed increase to the residential basic charge makes progress toward a more cost compensatory residential basic charge.[397] The current basic charge fails to cover the related costs of residential service, including the cost of meters, service drops, meter reading, and billing.[398] Based on the cost of service results submitted by Company witness Mr. Paice, a basic charge of $10.27 is appropriate.[399] The Company's proposed $8.50 basic charge is a reasonable compromise.

137. The Energy Project witness Mr. Eberdt argued that raising the Basic Charge sends an anti-conservation message and unfairly impacts low-use customers, many of whom Mr. Eberdt argues are low-income customers.[400] The Company's proposal includes an increase to energy charges in an inverted rate structure by more than 18%, sending an appropriate conservation signal to customers.[401] The Company's proposal also improves equity for all customers by reflecting more of the fair share of fixed costs in the Basic Charge.[402] Moreover, low-income customers do not have lower consumption than non-low-income customers, so Mr. Eberdt's argument conflating these groups of customers should be disregarded.[403]

C. The Company's Cost of Service was Developed Consistent with Commission Precedent.

138. ICNU witness Mr. Schoenbeck objects to the Company's cost of service study on the basis that it uses 100 winter hours and 100 summer hours for allocating system demand related

---

396 Griffith, Exh. No. WRG-7T 3:11-13.
397 Griffith, Exh. No. WRG-7T 3:22-23.
398 Griffith, Exh. No. WRG-7T 3:15-18.
399 Griffith, Exh. No. WRG-7T 3:18-20.
400 Eberdt, Exh. No. CME-1T 13:16-19; 14:6-8.
401 Griffith, Exh. No. WRG-7T 4:5-7.
402 Griffith, Exh. No. WRG-7T 4:8-11.
403 Griffith, Exh. No. WRG-7T 5:7-9.

costs.[404] Mr. Schoenbeck argues that the factor encompasses too many hours for accurately assigning system demand costs and because giving equal weight to each hour ignores the fundamental driver of generation and transmission investment.[405] Mr. Schoenbeck argues that the peak demand allocation factor should be determined considering only those hours that are within 95% of the system peak hour.[406]

139. The Commission previously rejected Mr. Schoenbeck's proposal in Docket UE-920499.[407] The Company also used the methodology used in this case in its previous three rate cases in Washington.[408] For these reasons, and those discussed in the testimony of Company witness Mr. Paice,[409] ICNU's proposal should be rejected.

IX. LOW INCOME FUNDING

A. The Company's Low Income Bill Assistance Proposals are Reasonable.

140. The Company recommends that the Commission adopt the changes to the Low Income Bill Assistance program outlined in Company witness Mr. Griffith's testimony,[410] along with Staff witness Mr. Schooley's proposal to increase the low income Schedule 91 surcharge collection by the increase originally proposed by the Company and not adjust it for the final rate change.[411] The Company's proposal would increase the number of participating customers with 30% of the additional funds collected, increase the rate credit with 70% of the additional funds collected, and revise the recertification process to every other year.[412] With respect to The Energy Project witness Mr. Eberdt's proposal to increase the agency administrative fee by 35%,

[404] Schoenbeck, Exh. No. DWS-1T 2:18-23.
[405] Schoenbeck, Exh. No. DWS-1T 3:2-3; 9-10.
[406] Schoenbeck, Exh. No. DWS-1T 3:15-16.
[407] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Docket UE-920499, 9th Supp. Order on Rate Design Issues at 12 (Aug. 17, 1993).
[408] Paice, Exh. No. CCP-6T 2:13-15.
[409] Paice, Exh. No. CCP-6T 2:2-4:13.
[410] Griffith, Exh. No. WRG-1T 7:3-16.
[411] Griffith, Exh. No. WRG-7T 6:10-15.
[412] Eberle, Exh. No. RME-1T 2:6-17, 6:12-21.

the Company recommends that the Commission reject this proposal, but proposes that Commission Staff convene a meeting of interested parties to evaluate how the certification process can be modified to lower agency costs and thereby increase benefits to low-income customers.[413]

B. There is Currently No Reason to Increase Low Income Weatherization Funding.

141. The Energy Project proposes to increase funding through the Company's low income weatherization program by 50%, or approximately $500,000.[414] The Company objects to this proposal on the basis that the current budgeted amount of $1 million is not being fully used.[415] Using the existing budget in full would result in a realized increase in funding of about 45%.[416] The Energy Project's proposal is therefore unnecessary.

X. CONCLUSION

142. For the reasons discussed above, the Company respectfully requests that the Commission issue an order approving the Company's revenue requirement increase of $47.7 million to be effective April 3, 2011, together with the Company's proposed rate spread and recommendations related to low income programs.

DATED: February 11, 2011.

Respectfully Submitted,

for

Katherine A. McDowell
McDowell Rackner & Gibson PC
419 SW 10th Avenue, Suite 400
Portland, OR 97205
Telephone: (503) 595-3924
Facsimile: (503)595-3928
Email: katherine@mcd-law.com

[413] Eberle, Exh. No. RME-1T 7:10-19.
[414] Eberdt, Exh. No. CME-1T 14:12-15; 15:12-14.
[415] Eberle, Exh. No. RME-1T 8:2-21.
[416] Eberle, Exh. No. RME-1T 8:22-9:6.

Attorneys for PacifiCorp

Jordan White
Senior Counsel
PacifiCorp
1407 W. North Temple, Suite 320
Salt Lake City, UT 84116
Telephone: (801) 220-2279
Facsimile: (503) 813-7252
Email: jordan.white@pacificorp.com

Appendix A

The table below presents the Company's contested and uncontested ratemaking adjustments and their impact on net operating income (NOI), rate base, and the Washington revenue requirement.

		NOI	Rate Base	Rev. Req.	Reference
Unadjusted Washington Allocated Data (Per Books)		**46,232,662**	**751,399,887**	**26,511,726**	(RBD-2) - Revised 11/23/10, Page 1
Uncontested Adjustments					
3.2	Revenue Normalization (3)	(69,998)	2,751,332	483,092	(RBD-3), Page 3.0 Total
3.3	Effective Price Change (3)	8,061,401	-	(13,004,776)	(RBD-3), Page 3.0 Total
3.6	Wheeling Revenue Adjustment	60,438	-	(97,500)	(RBD-3), Page 3.0 Total
4.1	Miscellaneous General Expense Adjustment	28,780	-	(46,428)	(RBD-3), Page 4.0 Total
4.4	Pension Curtailment	474,858	-	(766,048)	(RBD-3), Page 4.0 Total
4.6	DSM Removal Adjustment	3,198,895	472,406	(5,096,948)	(RBD-3), Page 4.0 Total
4.7	Remove Non-Recurring Entries	127,808	-	(206,181)	(RBD-3), Page 4.0.1 Total
4.8	Remove MEHC Severance	397,117	(306,376)	(681,856)	(RBD-3), Page 4.0.1 Total
5.1	Net Power Costs - Restating	7,150,053	-	(11,534,575)	(RBD-3), Page 5.0 Total
5.3	Electric Lake Settlement	(98,983)	(212,583)	131,080	(RBD-3), Page 5.0 Total
5.4	BPA Residential Exchange	(5,216,329)	-	8,415,062	(RBD-3), Page 5.0 Total
5.5	James River Royalty Offset	766,070	-	(1,235,836)	(RBD-3), Page 5.0 Total
5.6	Removal of Colstrip #3	274,987	(8,160,130)	(1,541,495)	(RBD-3), Page 5.0 Total
6.1	Hydro Decommissioning	-	(264,084)	(35,530)	(RBD-3), Page 6.0 Total
7.2	Accum. Def. Income Tax Factor Correction	-	(5,199,035)	(699,489)	(RBD-3), Page 7.0 Total
7.3	Renewable Energy Tax Credit	5,638,736	-	(9,096,497)	(RBD-3), Page 7.0 Total
7.4	Malin Midpoint Adjustment	291,667	(510,417)	(539,194)	(RBD-3), Page 7.0 Total
7.5	WA - FAS 109 Flow-Through	(5,532,834)	-	8,925,653	(RBD-3), Page 7.0 Total
7.6	AFUDC - Equity	75,955	-	(122,531)	(RBD-3), Page 7.0 Total
7.7	Public Utility Tax Adjustment	257,639	-	(415,628)	(RBD-3), Page 7.0.1 Total
7.8	Remove Deferred State Tax Expense	2,199,228	1,099,614	(3,399,884)	(RBD-3), Page 7.0.1 Total
7.10	Medicare Deferred Tax Expense	(170,464)	-	274,996	(RBD-3), Page 7.0.1 Total
7.11	Avg Balance for Accum Def Inc Tax - Property	-	(9,873,199)	(1,328,362)	(RBD-3), Page 7.0.1 Total
7.12	WA Low Income Tax Credit	20,962	-	(33,815)	(RBD-3), Page 7.0.1 Total
8.3	Environmental Remediation	(37,050)	261,509	94,954	(RBD-3), Page 8.0 Total - Revised 11/23/10
8.4	Customer Advances for Construction	-	23,143	3,114	(RBD-3), Page 8.0 Total - Revised 11/23/10
8.5/8.5.1	Miscellaneous Rate Base	13,847	(6,166,835)	(852,037)	(RBD-3), Page 8.0 Total - Revised 11/23/10
8.6	Removal of Colstrip #4 AFUDC	17,991	(441,006)	(88,357)	(RBD-3), Page 8.0.1 Total - Revised 11/23/10
8.7	Powerdale Hydro Removal	109,264	462,824	(113,997)	(RBD-3), Page 8.0.1 Total - Revised 11/23/10
8.8	Trojan Unrecovered Plant Adjustment	99,958	748,258	(60,582)	(RBD-3), Page 8.0.1 Total - Revised 11/23/10
8.9	Customer Service Deposits	(22,103)	(2,980,496)	(365,345)	(RBD-3), Page 8.0.1 Total - Revised 11/23/10
8.10	Chehalis Reg Asset - WA	(1,861,470)	9,488,085	4,279,500	(RBD-3), Page 8.0.1 Total - Revised 11/23/10
12.1	SO2 Emission Allowances	332,038	(2,334,188)	(849,695)	(RBD-6) - Revised 12/10/10, Page 12.0 Total
12.2	SERP Expense	110,289	-	(177,920)	(RBD-6) - Revised 12/10/10, Page 12.0 Total
12.4	Advertising Expense	1,178	-	(1,901)	(RBD-6) - Revised 12/10/10, Page 12.0 Total
12.5	Green Tag (REC) Revenues	372,097	-	(600,272)	(RBD-6) - Revised 12/10/10, Page 12.0 Total
12.7/12.7.1	Production Factor Adjustment	187,794	(783,879)	(408,417)	(RBD-6) - Revised 12/10/10, Page 12.0.1 Total
12.9	Interest True -Up	(1,226,799)	-	1,979,092	(RBD-6) - Revised 12/10/10, Page 12.0.1 Total
	Subtotal Uncontested Adjustments	**16,033,016**	**(21,925,058)**	**(28,814,554)**	
Contested Adjustments					
3.1	Temperature Normalization	(4,357,889)	-	7,030,214	(RBD-3), Page 3.0 Total
4.2	General Wage Increase - Annualization	(18,800)	-	30,329	(RBD-3), Page 4.0 Total
4.3	General Wage Increase - Pro Forma	(243,032)	-	392,062	(RBD-3), Page 4.0 Total
7.9	Current Year Def Inc Tax Normalization	(525,562)	(262,781)	812,490	(RBD-3), Page 7.0.1 Total
8.2	Jim Bridger Mine Rate Base Adjustment	-	34,717,942	4,671,027	(RBD-3), Page 8.0 Total - Revised 11/23/10
12.3	Affiliate Management Fee	59,810	-	(96,486)	(RBD-6) - Revised 12/10/10, Page 12.0 Total
12.6	Pro Forma Net Power Costs	(22,600,645)	-	36,459,710	(RBD-6) - Revised 12/10/10, Page 12.0 Total
12.8	Cash Working Capital	-	11,169,894	1,502,822	(RBD-6) - Revised 12/10/10, Page 12.0.1 Total
	Subtotal Contested Adjustments	**(27,686,119)**	**45,625,056**	**50,802,168**	
	Company's Rebuttal Filing	**34,579,560**	**775,099,885**	**48,499,340**	(RBD-6) - Revised 12/10/10, Page 1.0

Notes:

(1) The figures above do not reflect the impact of the Company's response to Commission Bench Request 3. In that response, the Company further reduced the Washington revenue requirement for pro forma net power costs by approximately $750k.

(2) The revenue requirement column is calculated using the Company's proposed return on rate base of 8.35% and the NOI conversion factor of 61.988%. The development of these percentages can be found in Exhibit No.___(RBD-6) - Revised 12/10/10 on pages 2.1 and 1.3 respectively.

(3) The present rates used in these adjustments have not been contested. However, ICNU/Public Counsel witness Mr. Meyer contests the normalized load levels.

Appendix B

Net Power Cost Adjustments

Item	Issue	Proposed Company Adjustment[1]	Proposed Staff Adjustment	Proposed ICNU Adjustment
	Adjustments Accepted in Whole in the Company's Rebuttal Testimony			
1	Commitment Logic Screens (ICNU 2)	$239,639	N/A	$973,338
2	SMUD Contract Sales (ICNU 6)	$19,039	N/A	$19,039[2]
3	Inter-hour Wind Integration for Non-Owned Resources (Staff G, ICNU 12)	$220,983	$317,028[3]	$316,894
4	Adjustments Accepted in Part in the Company's Rebuttal Testimony			
5	PACE Transmission Cost (ICNU 8)	$12,836	N/A	$12,889[4]
6	Non-firm Transmission (ICNU 10)	-$274,089	N/A	$159,576
7	Modeling of Intra-Hour Wind Integration (ICNU 11)	$124,445	N/A	$124,913
8	Colstrip Planned Outage Schedule (ICNU 16)	$119,286	N/A	$119,286[5]
9	SCL Stateline Termination (Staff B, ICNU 5)	$349,229	$471,416	$878,014
	Fully Contested Adjustments			
10	GRID Arbitrage Margins (Staff A, ICNU 1)	N/A	$527,315	$585,874
11	Eastern Market Modifications (ICNU 3 and 4)	N/A	N/A	$502,308
12	Colstrip Wheeling Expense (ICNU 7)	N/A	N/A	$45,691
13	Idaho Point-to-Point Contract (Staff F, ICNU 8)	N/A	$351,118	$351,099[6]

[1] All amounts are Washington-allocated.
[2] ICNU 6 does not identify the impact of limiting the energy-take of SMUD to 346,400MWh/year. As a result, the value is approximated from the Company's run, given that the Company applied the same methodology as ICNU stated.
[3] The value is developed based on Staff Exhibit APB-6, by taking 22.18% of the total Inter-Hour Cost of $1,429,342.
[4] The value is developed based on the workpaper that supports ICNU 8.
[5] ICNU 16 does not identify the impact of moving planned outage schedule for Colstrip 4 only. As a result, the value is approximated from the Company's run, given that the Company applied the same methodology as ICNU stated.
[6] This is ICNU 8, excluding PACE Transmission Cost listed as item 5.

14	DC Intertie (Staff E, ICNU 9)	N/A	$1,057,187	$1,057,130
15	OATT Wind Integration Charges (Staff G, ICNU 13-15)	N/A	$903,793[7]	$506,607
16	Colstrip Outage (Staff D, ICNU 17)	N/A	$342,889	$376,492
17	Bridger Plant Fuel Derations (ICNU 18)	N/A	N/A	$650,958
18	Hermiston Planned Outage Schedule (ICNU 16)	N/A	N/A	$310,427[8]
19	SMUD Delivery Pattern (Staff C, ICNU 6)	N/A	$554,460	$439,484[9]
20	Minimum Loading and Deration (ICNU 19)	N/A	N/A	$299,897

[7] This is Staff Exhibit APB-6, excluding Inter-Hour Cost listed as item 3.
[8] This is ICNU 16, excluding the impact of moving the planned outage for Colstrip 4 listed as item 8.
[9] This is ICNU 6, excluding the impact of limiting SMUD energy-take to 350,400MWh/year listed as item 2.