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October 8, 2004

BY MESSENGER

Carole J. Washburn, Secretary
Washington Utilities and Transportation Commission
1300 S Evergreen Park Drive SW
PO Box 47250
Olympia, WA 98503-7250

Re: ***PacifiCorp dba Pacific Power & Light - 2004 General Rate Case***
Docket No. UE-032065

Dear Ms. Washburn:

Enclosed for filing in the above referenced matter are original and 16 copies of PacifiCorp's Post-Hearing Brief. An electronic copy is also being sent directly to the Records Center.

Very truly yours,

James M. Van Nostrand

JMV:hhs
Enclosures
cc: Service List

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP, d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	NO. UE-032065 PACIFICORP'S POST-HEARING BRIEF

DATED: October 8, 2004

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Of Attorneys for PacifiCorp

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I. PROCEDURAL BACKGROUND

1. This proceeding, which was commenced with PacifiCorp's filing of revised tariff schedules[1] on December 16, 2003, was authorized by the Commission in its Sixth Supplemental Order in Docket No. UE-020417 (the "Deferred Power Cost Proceeding"). In that Order, the Commission modified its final order in the Company's 1999 General Rate Case[2]—which adopted a multi-year Rate Plan for the Company—to permit the Company to make a general rate filing prior to the end of the Rate Plan Period. Following a thorough investigation by all parties to the proceeding—and just prior to the commencement of hearings—the Company and Commission Staff reached agreement on a proposed settlement (the "Settlement Agreement"), which was later joined in by Natural Resources Defense Council ("NRDC"). This Agreement was filed with the Commission on August 27, 2004 (*Exh. No. 3*), accompanied by joint supporting testimony. This testimony, as well as testimony in opposition to the Settlement Agreement offered by the Public Counsel Section of the Office of Attorney General ("Public Counsel") and Industrial Customers of Northwest Utilities ("ICNU"), was presented in four days of hearings before the Commission.

II. OVERVIEW OF THE CASE

2. The Company's residential rates in Washington are currently the lowest among the 175 investor-owned utilities in the nation, as surveyed by the Edison Electric Institute. *Exh. No. 509 at 6.* Its overall rate levels are the 14th lowest in the nation, according to the same survey. *Id. at 3.* PacifiCorp's rates in Washington today are lower than they were 15 years ago, during which period the Consumer Price Index has increased by nearly 60 percent. *Exh. No. 32 at 11:10-12 (Furman).* As a result, the Company's residential rates are the lowest of the three investor-owned utilities and the three largest customer-owned utilities in Washington. *Id. at 12:13 –*

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[1] The tariff filing submitted by the Company proposed to increase base prices to its Washington electric customers by $26.7 million (13.5 percent).

[2] Docket No. UE-991832, 3rd Supplemental Order.

13:4. Even with the requested increase, the Company's residential rates would be in the lowest two-fifths of all Washington utilities. *Exh. No. 21 at 4:3-5; Exh. No. 22* (*Johansen*). The Company's Washington customers have clearly benefited from the Company's integrated, six-state system and an extensive fleet of generating resources, which have produced relative rate stability notwithstanding the turbulent events in Western power markets over the past four years. By comparison, in late 2001 and 2002, utilities regulated by the Commission sought and received significant rate increases to alleviate the impacts of the Western energy crisis, including a 25 percent temporary rate increase and a 19 percent general rate increase for Avista Utilities[3] and a $25 million rate increase for Puget Sound Energy.[4] The impact on municipal utilities was even greater—a 47 percent rate increase for Seattle City Light,[5] a 43 percent increase for Tacoma Power,[6] a 53 percent increase for Snohomish PUD,[7] and a 46 percent increase for the Bonneville Power Administration ("BPA").[8]

3. It was in this context that the Commission determined in the Deferred Power Cost Proceeding that "the Rate Plan [had] been so overtaken by events that it no longer is in the public interest for the Company's rates to remain unexamined through the Rate Plan Period." *Sixth Supplemental Order* (*"Deferred Power Cost Order"*) ¶ *23*. The Commission therefore amended the Rate Plan to the extent necessary to permit the filing of a general rate case before the end of the Rate Plan Period. *Id.* Notably, the Order did not, on its face, impose any unusual requirements with respect to the contents of this general rate filing or the standards by which it

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[3] Docket No. UE-010395, 6th Supplemental Order (Sept. 2001); Docket No. UE-011595, 5th Supplemental Order (June 2002).

[4] Docket Nos. UE-011570 and UG-011571, 9th Supplemental Order (March 2002). This was followed by a $58.8 million increase in June 2002 (12th Supplemental Order).

[5] *See* www.cityofseattle.net/light/accounts/rates/ac5_sum.htm.

[6] *Wholesale Price Spikes Led to Regional Rate Hikes*, Clearing Up, Oct. 29, 2001, at 8.

[7] *Snohomish Board OKs 18 Percent BPA-Related Hike*, Clearing Up, Sept. 10, 2001, at 3.

[8] United States Department of Energy—Bonneville Power Administration, 104 FERC ¶ 61,093 (2003).

would be judged. Rather, the Order appeared to contemplate that the filing would be treated as a stand-alone general rate case filing, stripped of any constraints or considerations that may arise from considerations of what the Rate Plan would or would not have permitted.

4. ICNU and Public Counsel, however, seek to have this filing evaluated under a different, heightened standard, apparently grounded in the notion that had the Rate Plan not been modified, this case would not even have been commenced. This "heightened" standard is apparent in a number of references in the ICNU and Public Counsel testimony, including the following:

- ICNU witness Schoenbeck testified that "no increase is justified in this proceeding" because, without an increase, the Company assertedly would achieve a return on equity ("ROE") of between 7.16 percent and 7.35 percent. *TR. 125:11 – 125:5.* According to Mr. Schoenbeck, this range is "within the range of return on common equity that the Company had assumed would occur by this time during the rate plan." *TR. 124:23 – 125:1.*

- ICNU witness Falkenberg claims that "a very high standard of proof should be required of the Company in this case on all issues because it represents an early exit from the rate plan. Given this, the Company should be held to a very high standard." *Exh. No. 437 at 1.* According to Mr. Falkenberg, he applied this "very high standard" throughout his analysis of the Company's power supply issues. *TR. 560:1-5.*

- Mr. Falkenberg further claims that "the Commission could merely rescind its order in Docket No. UE-020417, because its expectations for allowing the Company to file this case have not been met by the Company." *Exh. No. 445 at 1.* During cross-examination, Mr. Falkenberg explained that this failed "expectation" was "the lack of an MSP solution." *TR. 563:17-21.*

- Both ICNU witness Schoenbeck and Public Counsel witness Lazar recommend that the effective date for any rate increase granted in this proceeding be delayed until January 1, 2006, which is the date the Rate Plan adopted in the 1999 General Rate Case expires. *TR. 127:14-17 (Schoenbeck); TR. 397:12-14 (Lazar).*

5. These arguments evince a fundamental flaw in ICNU's and Public Counsel's analyses of this filing. From these arguments, it would seem that the Deferred Power Cost Proceeding never occurred, and that the Commission did not modify the Third Supplemental Order in the 1999 General Rate Case to expressly permit this general rate filing to be made. Notably, both ICNU and Public Counsel have appealed the Commission's decision from the Deferred Power Cost Proceeding, and that appeal is currently pending in the Court of Appeals (*Case No. 31826-1-II*) following dismissal of the appeal by Thurston County Superior Court. *Case No. 03-2-01614-1.* Until such time as a court rules otherwise, however, that order remains valid and fully effective. *RCW 80.04.180.* By their characterization of the issues above, ICNU and Public Counsel are attempting to relitigate the issues from the Deferred Power Cost Proceeding in this case—or worse, disregarding the relief granted by the Commission in that case. It is a fundamental flaw in their analyses that renders substantial portions of their cases meaningless. Mr. Falkenberg's entire analysis of power cost issues, for example, was evaluated from the perspective that a "very high standard" should be applied to the Company's filing. *TR. 560:1-5.*

6. Similarly, there is nothing in the Deferred Power Cost Order suggesting that a reasonable ROE will be determined by reference to what "the Company had assumed would occur by this time during the rate plan." *TR. 124:23 – 125:1 (Schoenbeck).* In fact, the order states the contrary:

> Balanced against that [a rate increase sooner than expected] . . . is the need to provide PacifiCorp an opportunity to earn a reasonable return over the next several years; that is, maintaining sufficient rates. *Exh. No. 450 ¶ 41.*

Nor is there any language in the order that required the interjurisdictional cost allocation issue to be resolved in this proceeding as a condition precedent to this filing going forward. While there is language in the order expressing the view that the Multi-State Process ("MSP") "is expected to be finalized by the middle of this year [2003]" and that "[t]he outcome of that process should inform PacifiCorp's filing with respect to the important question of interjurisdictional cost allocation issues" (*Exh. No. 450 at 11 fn.10*), that language does not establish resolution of this issue as a condition precedent to this filing going forward. In fact, this very issue was resolved by the Commission at its January 14, 2004 Open Meeting where it considered and rejected a recommendation from Staff—based on the same reading of the Deferred Power Cost Order—that the filing be dismissed.

7. Finally, the recommendation that the effective date of any rate relief be delayed until January 1, 2006 is unlawful. RCW 80.04.110(3) authorizes the Commission to suspend a filing for 10 months beyond the 30-day period included in a proposed tariff revision. That suspension period expires on November 16, 2004 in this case. There is no basis upon which the effective date can be delayed an additional 13½ months, as ICNU and Public Counsel propose. Their proposal plainly contravenes the Commission's ruling in the Deferred Power Cost Order—which amended the Rate Plan to permit this filing to be made and processed as a stand-alone general rate case filing, without regard to what the Rate Plan would or would not have permitted. Relitigating the Deferred Power Cost Proceeding should occur, if at all, only in the proper forum, which is currently the Court of Appeals. PacifiCorp respectfully submits that incorporation of these issues in this proceeding has infected ICNU's and Public Counsel's analyses in a manner that is fatal to their presentations.

III. THE COMMISSION SHOULD ADOPT THE STAFF/PACIFICORP/NRDC SETTLEMENT AGREEMENT

A. Overview of Terms of Settlement Agreement.

8. The Settlement Agreement contains the following elements:

- Presentation of the revenue requirement on the basis of the original Protocol cost allocation methodology, which will be used for purposes of this proceeding only. Until a permanent solution is agreed upon, the Revised Protocol will be used for purposes of routine regulatory filings. *Exh. No. 3 ¶ 8(b).*

- A recommended revenue requirement increase of $15.5 million, calculated on the basis of the adjustments listed in Attachment A. *Id. ¶ 9.* This revenue requirement increase reflects an overall rate of return of 8.39 percent, *id. ¶ 10(a)*, and annual net power costs of $534.1 million, which were calculated on the basis of the power cost adjustments listed in Attachment B, *id. ¶ 10(b).*

- A finding of prudence with respect to the Company's Hermiston and James River resources, with the prudence of the Company's resources in the Eastern Control Area (West Valley, Gadsby, Craig, Hayden, Foote Creek, and Cholla) to be evaluated in a subsequent proceeding, if necessary, depending upon the interjurisdictional cost allocation methodology. *Id. ¶ 10(c).*

- Adoption of the proposed rate spread and rate design proposals set forth in the joint Staff/ICNU/Public Counsel testimony. *Id. ¶ 11.*

- Proposed treatment of currently pending requests relating to regulatory assets and deferred debits. *Id. ¶ 12.*
- Recommended consideration of whether it is in the public interest to investigate a true-up mechanism designed to eliminate financial disincentives associated with demand-side initiatives. *Id. ¶ 13.*
- Proposals regarding procedural issues, including a recommendation that if the Settlement Agreement is rejected or modified and additional proceedings necessitate the extension of the suspension period, the Commission implement a rate increase as of the end of the suspension period, subject to refund pending issuance of a final order. *Id. ¶ 14(d).*

B. Overview of the Opposition to the Settlement Agreement.

9. As its basis for opposing the Settlement Agreement, ICNU witness Schoenbeck identified five reasons. Each of these reasons, and the Company's response to it, is set forth briefly below:

ICNU Basis for Opposition	Company Response
Original Protocol should not be adopted as basis for interjurisdictional cost allocations. *TR. 121:8-10, 141:12-18 (Schoenbeck).*	• Use of the original Protocol is an interim solution that provides the only common basis for evaluating the various proposed adjustments in the case. • The settling parties have proposed a process for developing a durable solution to the interjurisdictional cost allocation issue.
Implied ROE under Settlement Agreement is too high. *TR. 121:10-11, 129:17 – 130:8 (Schoenbeck).*	• The Settlement Agreement does not identify a particular ROE. • The stipulated overall Rate of Return of 8.39 percent falls reasonably between the 7.72 percent proposed by Staff/Public Counsel and the 8.743 percent proposed by the Company. • Any analysis that purports to suggest a particular ROE is inconsistent with the express terms of the Settlement Agreement. *Exh. No. 1 at 10:18-22 (panel).*

Settlement Agreement assumes inclusion of West Valley in rates even though, according to ICNU, units will be removed from service.[9] *TR. 121:11-15, 131:16 – 132:3 (Schoenbeck).*	• West Valley will have provided service throughout the test period and the pro forma period in this case. • Whether or not the Company ultimately terminates the lease—which in no event will occur sooner than May 31, 2005—has no impact on the appropriateness of inclusion of the West Valley resource for purposes of setting rates in this case.[10] • In any event, Staff has preserved the ability to challenge the inclusion of West Valley costs in Washington rates in a future proceeding. *Exh. No. 3 ¶ 10(c).*
Deferred accounting treatment for Trail Mountain mine and environmental remediation costs is inappropriate. *TR. 121:15-18, 134:19 – 135:11* (*Schoenbeck*).	• Accounting petitions for these items were filed before this general rate case filing, and the Company requested that they be considered as part of this proceeding. The requested accounting treatment was part of this case, and was examined by the parties. *TR. 343:12-14, 345:8-12* (*Omohundro*). • The opportunity sought by ICNU "to review the associated costs, the prudency of those costs, and what should be included," *TR. 135:5-11* (*Schoenbeck*), was in fact provided in this proceeding, and ICNU chose not to offer testimony challenging the requested treatment.
Settlement Agreement contemplates "interim rates," without a showing of financial distress. *TR. 121:24 – 122:3, 141:24 – 142:5* (*Schoenbeck*).	• Paragraph 14(d) of the Settlement Agreement comes into play only if (1) the Company is required to extend the suspension period to accommodate additional processes, and (2) the Commission adopts a revenue requirement different than the $15.5 million recommended in the Settlement Agreement. • This is not "interim relief" as that term has been used in prior Commission orders (*TR. 348:14-16* (*Omohundro*)), and the Settling Parties do not purport to show that the Company is in such financial distress that "interim relief" could be justified.

[9] Mr. Schoenbeck indicated that Mr. Falkenberg would offer additional testimony to support this contention. *TR. 131:16 – 132:3*. Notably, Mr. Falkenberg—the witness more familiar with the Company's power supply resources and its acquisition process—offered no additional testimony on this point.

[10] See Exhibit 142, which is the RFP conducted by the Company to consider possible replacements for the West Valley resource. According to that exhibit, even though PacifiCorp exercised its first option to terminate the lease, that termination can be rescinded by September 30, 2004, depending upon the outcome of the RFP. The replacement resource must be available June 1, 2005, upon the effective date of the lease termination. *Exh. No. 142 at 3*.

10. As an additional basis for rejecting the Settlement Agreement, Mr. Falkenberg urged adoption of those of his proposed adjustments that were ***not*** included in the Settlement Agreement, which total about $7.7 million. *Exh. No. 425* (*Falkenberg*). These additional adjustments should not be adopted, for the reasons set forth in Section III.E.3 below.

11. Public Counsel, for its part, appears to agree with point 5 above—that any rate relief should be deferred until January 1, 2006—but did not offer other testimony in opposition to the Settlement Agreement, other than rejection for the reason that the Settlement Agreement failed to incorporate Mr. Lazar's proposed "hydro situs" proposal for interjurisdictional cost allocations and certain remaining adjustments offered by Public Counsel witness Dittmer. Mr. Lazar's "hydro situs" proposal is discussed in Section III.C.5 below, while Mr. Dittmer's unadopted adjustments are presented in Section III.D.3 below.

C. The Commission Should Adopt the Settlement Proposal Regarding Interjurisdictional Allocation Issues.

1. Background on the Multi-State Process.

12. Mr. MacRitchie's direct testimony describes PacifiCorp's nearly four-year quest to resolve a number of long standing issues arising from its status as a multistate utility subject to the jurisdiction of six regulatory commissions. *Exh. No. 61 at 3:9 – 7:11.* The process known as MSP commenced in March 2002, when the Company made a set of filings requesting that the Company's state commissions initiate investigations and endorse a collaborative process to address interjurisdictional issues facing PacifiCorp. These filings were broadly supported by the Company's state commissions.[11] *Id. at 4:10-14.* The Company had three fundamental objectives with respect to the MSP:

1. To establish interjurisdictional cost allocation mechanisms that would permit it to continue to plan and operate its generation and transmission system on an integrated basis,

[11] The Commission supported the MSP but preferred not to open a docket in connection with it. *Docket No. UE-020319, Order Denying Petition and Authorizing Participation in Multi-State Discussions.* Key staff members in California monitored the proceedings and received relevant documents.

2. To establish uniform interjurisdictional cost allocation methods among its six jurisdictions that would provide it with a reasonable opportunity to earn a return on future investments in generation and transmission facilities, and

3. To preserve the ability of each of its jurisdictions to implement individual state energy policies in a manner that does not unreasonably burden customers in other jurisdictions.

Exh. No. 32 at 3:15 – 4:1 (Furman).

13. Mr. MacRitchie's direct testimony (Exh. No. 61) at pages 4-7 describes the process that led to the development of the Protocol. In September 2003, the Protocol was filed with the Utah, Oregon, Wyoming, and Idaho commissions. These filings were supported by substantial testimony and analyses. *Id. at 6:11-16.* Since those filings were made, "all-party" stipulations have been entered into in Utah and Wyoming and a stipulation has been entered into with all parties to the Oregon proceedings other than ICNU. The Company is awaiting decisions from the Oregon and Utah commissions. Wyoming hearings are scheduled for mid-October. *TR. 238:20 – 239:15(Furman).*[12]

2. Interjurisdictional Cost Allocation Issues in This Case.

14. The Company did not file the Protocol in Washington at the same time that it made filings in other states. This is because the Company had concluded, based upon the Commission's final order in the Deferred Power Cost Proceeding, that the Commission's preference was to deal with allocation issues in the context of a general rate proceeding.[13] Accordingly, the Protocol was subsequently made part of the Company's December 16, 2003 filing in this case. *Exh. No. 32 at 5:12-16 (Furman).*

15. Staff and intervenor responsive testimony was not supportive of the Protocol. Staff proposed use of a "control area" approach for purposes of this case, pending further development of allocation methods based more on an "islanding" approach that would seek to allocate the

[12] As discussed further below, these stipulations are based upon a "Revised Protocol" which is different than the Original Protocol included by the Company in its direct case.

[13] Staff also reached this conclusion. *Exh. No. 581 at 110:18-19 (Buckley).*

costs of resources deemed to be used to provide service to Washington customers. *Exh. No. 581 at 105:13-20 (Buckley)*. Public Counsel proposed a control area approach modified to assign all hydroelectric resources located in Washington directly to Washington. *Exh. No. 501 at 1:16-26 (Lazar)*. ICNU proposed that the Protocol be "rejected" by the Commission and allocation issues dealt with in a bifurcated proceeding with emphasis on the further development of a control area approach. Alternately, ICNU proposed various adjustments and changes to the Protocol method. *Exh. No. 401C at 5:8-17, 70:19 – 71:8 (Falkenberg).*

16. Considering allocation issues in the context of a Washington general rate case proceeding, while participating in less formal ratification processes in other states, gave rise to procedural challenges and controversy in Washington. When PacifiCorp filed the Protocol as a part of its direct case in this proceeding, it believed that the form of the Protocol would be very close to that adopted in other states. *TR. 202:17-21 (Furman)*. However, as a result of continuing discussions with Utah and Oregon parties, a Revised Protocol was developed well after the Company's direct testimony was filed in this proceeding and some 40 days before Staff and intervenor response testimony was due. *Exh. No. 32 at 6:16-20 (Furman)*. The Company found itself in the difficult position of having to continue to prosecute this case because of its need for additional revenue, notwithstanding the fact that the MSP issues remained unresolved. *TR. 202:22-25 (Furman)*. The Company had come to understand that the MSP was "iterative and somewhat serial" and that it was not going to get the same protocol approved at the same time in every jurisdiction. *Id. at 205:10-13.*

17. Because of numerous references to the Revised Protocol in response testimony filed by other parties, the Company elected to file the Revised Protocol as an exhibit to Ms. Kelly's rebuttal testimony. *Exh. No. 32 at 7:11-13 (Furman)*. Mr. Furman's rebuttal testimony stated the following regarding the Revised Protocol:

> Although our preference would be that Washington rates be established based upon the Revised Protocol, we are mindful of the procedural concerns raised by other parties to this proceeding.

> Given these circumstances, we would not oppose deciding this case on the basis of the original Protocol included in the Company's direct case. *Exh. No. 32 at 7:5-9.*

18. Ultimately, the Company, Staff, and NRDC entered into a Settlement Agreement that resolved all issues in this proceeding as among them. As explained by Mr. Braden, the numerical "starting point" for the revenue requirement adjustments shown in the Settlement Agreement is the original Protocol because it provided the only common basis upon which the parties could evaluate each other's proposed adjustments. *TR. 322:22 – 323:22.* However, the Settlement Agreement expressly provides that the original Protocol is to be used for this proceeding only, and that no party to the Settlement Agreement is to be deemed to be agreeing that the original Protocol is sufficient or proper for use in any future proceedings before the Commission. *Exh. No. 3 ¶ 3(b).*

19. Neither Public Counsel nor ICNU supports the Settlement Agreement. However, ICNU now appears to believe that if allocation issues are to be resolved in this proceeding, it should be based upon some modified version of the Revised Protocol. *TR. 538:18-23 (Falkenberg).*[14]

20. Commissioner Hemstad aptly described the quandary faced by the Commission and the parties in respect to resolving interjurisdictional cost allocations in this case:

> The Company has filed a case based on the protocol, which it now does not itself support. Staff prepared the case using a control area that . . . it would want to only use for this case . . . not on a going forward basis. And the Company has now filed a revised protocol for at least informational purposes that it would appear to essentially support, but the Staff is unprepared to come to any conclusions about it, so we have three different allocation methods, none of which seem to have anybody's . . . comprehensive support for any of them. *TR. 658:2-14.*

21. PacifiCorp acknowledges that these are less than perfect circumstances that it did not intend. *TR. 203:6-13 (Furman).* Nonetheless, the Company believes that the quandary

[14] However, as Ms. Kelly testified, the "modifications" to the Revised Protocol proposed by Mr. Falkenberg are so substantial as to constitute the fifth different proposed allocation methodology in the record in this case. *TR. 777:4-17.*

described by Commissioner Hemstad (and alluded to by all three Commissioners in their questions) should be resolved in a way that furthers three important objectives:

1. The resolution of interjurisdictional cost allocation issues should not further perpetuate the Company's material revenue shortfall in Washington,

2. The process should permit a reasonable opportunity for Washington to align itself with PacifiCorp's other jurisdictions in respect to interjurisdictional cost allocation issues,[15] and

3. The process should permit a consensual resolution of interjurisdictional cost allocation issues among Washington parties.

22. Several witnesses were asked by Commissioners how they would propose to move forward in resolving allocation issues. Mr. Lazar proposed that there be substantial additional study of allocation issues and that there be no change in the Company's Washington rates until 2006, the end of the Rate Plan Period adopted in the Company's 1999 General Rate Case. *TR. 449:22 – 450:1.* Mr. Falkenberg, for his part, proposed that these proceedings be "bifurcated" with the Commission resolving the Company's total system costs in the first phase of the proceedings and resolving how those total costs should be allocated in a second phase.[16] *TR. 620:6-14, 624:16 – 625:4.* Mr. Braden testified that the Commission should adopt the Settlement Agreement so that the parties would have the ability to move forward to achieve a consensual resolution in respect to a permanent allocation method for Washington. *TR. 645:8-22, 647:1-4.* As discussed further below, the settling parties have set forth a specific proposal for a process regarding this permanent allocation method for Washington.

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[15] Mr. Falkenberg acknowledged that there was independent value in all of PacifiCorp's jurisdictions adopting a common allocation approach. *TR. 637:10-13.* However, in the Oregon MSP proceedings, ICNU took the position that "in any form or manner, now and for the long run" there would be "no" costs to ratepayers from not reaching an MSP agreement among the states. *Exh. No. 12 at 65:14 – 66:4.* Accordingly, in that proceeding, Mr. Falkenberg urged the Oregon Commission to resolve interjurisdictional cost allocation issues without regard to the acceptability of its decisions to other states. *Exh. No. 428 at 45:1-22.*

[16] Mr. Falkenberg also suggested that the Commission might adopt the Revised Protocol in these proceedings, without prejudice to the parties' ability to challenge it in future proceedings. *TR. 620:23 – 621:11.*

23. The suggested approaches of Messrs. Lazar and Falkenberg would obviously substantially delay the Company's ability to obtain timely rate relief in these proceedings. There would also be a disincentive to reach consensual agreement if resolution of allocation issues were a prerequisite to a rate change. Also, as testified to by Mr. Braden, achieving "open and free discussions" would be more difficult in a litigation context. *TR. 646:12-15.*

24. Concerns were raised that the approach recommended in the Settlement Agreement might create inappropriate incentives for the Company to delay filing a new rate case if a different allocation method is more beneficial to Washington consumers than the Protocol. However, Mr. Braden discounted this possibility, observing that the Company's need to recover escalating costs and its desire to resolve allocation issues would overwhelm any benefit from delaying the implementation of a new allocation method in Washington. *TR. 651:10-18.*

25. Concerns were also raised that if there is not a definitive resolution of allocation issues, problems could arise if the Company were to seek interim rate relief or deferred accounting orders. The possibility of such circumstances was acknowledged, with the understanding that until a permanent allocation method is established in Washington, the Company would be at some risk. *TR. 372:1-9(Schooley), 647:19 – 648:14 (Braden), 656:6 – 657:6 (Braden), 684:2-19 (Schooley), 686:19 – 687:16 (Schooley).*

26. The approach advocated in the Settlement Agreement will afford the Company an ability to promptly establish compensatory rates in Washington. This approach is also best adapted to permitting the Commission to consider MSP outcomes in other states and most conducive to achieving a consensual resolution among the Company and Washington parties.

3. The Original Protocol Provides a Reasonable Basis for Establishing Rates for Purposes of This Proceeding.

a. The Original Protocol Is the Only Allocation Method Supported and Fully Evaluated in the Record.

27. Staff's "control area" approach was not independently developed, but was instead based upon adjustments to a Company response to a Staff data request that asked the Company to

recast certain of its "Hybrid" studies conducted in the MSP during 2003.[17] Mr. Buckley's response testimony indicates that Staff's proposal reflected a reasonable approximation of Washington-allocated power costs that should be used only as a "transitional mechanism" for purposes of this case. *Exh. No. 581 at 111:13 – 114:25.* Mr. Buckley testified that the Commission should not at this time "consider adopting a control area-based cost allocation methodology for future use." *Id. at 115:2-4.* Mr. Braden stated that Staff did not see the control area approach as "a viable model going forward." *TR. 368:16-17.*

28. Public Counsel's modified control area approach was even more conceptual in nature and not supported by substantial numerical analyses. Mr. Lazar conceded that his proposal was not sufficiently developed that it could be used for setting rates in this proceeding and that further studies would be required. *Exh. No. 501C at 15:15-18; TR. 433:25 – 434:4.*

29. The only numerical analyses presented by ICNU were adjustments to the original Protocol.

30. Staff and intervenors did not perform or present any comprehensive review of the Revised Protocol. Staff witnesses testified that the Revised Protocol has not "been subject to any degree of scrutiny by the Staff" and that they were unsure of its implications for PacifiCorp's Washington customers. *TR. 324:2-9, 644:19 – 645:7 (Braden).* Mr. Lazar stated that he had not examined the Revised Protocol in any detail. *TR. 447:6-7.* Even without the benefit of this analysis, it was suggested that the $15.5 million revenue requirement recommended under the Settlement Agreement should be reduced by some amount to reflect the assertedly lower revenue requirement that the Revised Protocol would produce. Mr. Braden explained the invalidity of such an approach:

> Q. [W]ouldn't it be inequitable to accept the settlement based on original protocol, but say that we're going to use revised protocol on a going

[17] Mr. Falkenberg testified that the Hybrid proposal was not sufficiently developed to "practically apply it in this case." *Exh. No. 401C at 70:13-15.*

forward basis and not give the customers the benefit of the reduction in rates, whatever that may be, associated with revised protocol?

A. I can't characterize the situation the same way in order to give you a simple yes or no answer, because we don't feel that the settlement position of the Staff and our basis for entering into the stipulation is truly based on adoption of the original protocol. It's based on our evaluation of the overall case, looking at our own evaluation methodologies and then striking a compromise.

So I feel that the compromise in and of itself is fair, regardless of which allocation methodology you might use to add up or combine the numbers in different ways to reach that result. So it's really the bottom line revenue requirement that's encapsulated in the stipulation that we support as fair, just, reasonable and sufficient. *TR. 659:3-24.*

Mr. Braden also stated that any revenue requirement reduction associated with the Revised Protocol "has already been factored into the proposal that the parties have stipulated to." *Id. at 653:3-8.*

b. The Original Protocol Appears Favorable to Washington Customers During the Years That Rates Established in This Proceeding Are Likely to Be in Effect.

31. In the period since the PacifiCorp/Utah Power merger in 1989, the Company has not had a general rate case that was fully litigated to its conclusion. Thus, no post-merger allocation method has been formally adopted by the Commission and there is no agreement among the parties as to what constitutes an appropriate "benchmark" for evaluating the relative impacts of a proposed allocation method. However, based upon the Commission's last order in a contested rate case in Cause No. U-86-02, one could conclude that a "Rolled-in" method represents established Commission policy and is the proper starting point for evaluation. *TR. 411:3 – 412:14 (Lazar).* Alternately, one could look to the "Modified Accord" method, which the Company has used in recent years as the basis for rate case filings and regulatory reporting. *TR. 676:20 – 677:4 (Schooley).*

32. Mr. Falkenberg asserted that the original Protocol method is more costly to Washington customers than either the Rolled-in or Modified Accord methods. *Exh. No. 401C at 59:24-25; TR. 537:23 – 538:1.* However, Mr. Falkenberg's conclusions were based upon a 14-year present value analysis. Mr. Falkenberg's supporting exhibits show that in the nearer term, the original Protocol is substantially *beneficial* to Washington consumers, compared to either the Rolled-in or Modified Accord method. During 2005, 2006, and 2007, under the original Protocol, the average annual Washington revenue requirement is reduced by approximately $4.6 million compared to the Rolled-in method and approximately $2.5 million compared to Modified Accord method. *Exh. No. 406C at 34.*

c. *Some of the More Controversial Attributes of the Original Protocol Are Irrelevant to the Rates Established in This Proceeding.*

33. Mr. Buckley's responsive testimony is critical of the Protocol provision that permits Oregon to opt out of supporting the costs of a major coal resource. *Exh. No. 581 at 56:5-9.* Mr. Falkenberg observes that this provision is inconsistent with the provisions of the Revised Protocol. *Exh. No. 401C at 58:1-2.* The Company's revenue requirement in this proceeding reflects no such new coal resource, however. Mr. Buckley also contends that the Protocol would not equitably allocate the costs of the Company's planned Lakeside and Currant Creek projects, although he acknowledges that those projects are not a subject of these proceedings. *Exh. No. 581 at 92:16 – 93:19.*

34. Similarly, Mr. Falkenberg faults the original Protocol for not adequately dealing with "cost shifts" to Washington consumers arising from relatively faster load growth in Utah. He suggests that the magnitude of this cost shift is in excess of $40 million, but again this is a 14-year present value calculation. *Exh. No. 401C at 68:4-7.* In contrast, Mr. Falkenberg's supporting exhibit shows no cost shift to Washington in 2005 and an apparent $403,000 *benefit* to Washington consumers from faster Utah load growth in 2006. *Exh. No. 420C at 1.*

d. *The Settling Parties Have Proposed a Process That Should Achieve Early Resolution of the Cost Allocation Issue.*

35. As described by Mr. Buckley, Mr. Schooley and Ms. Kelly, the settling parties have developed a specific proposal and timeline for development of a permanent Washington solution of the interjurisdictional cost allocation issue. Immediately following commission orders in Utah and Oregon—and no later than December 1, 2004—formal discussions would be initiated. *TR. 764:24 – 765:3 (Buckley).* On April 1, 2005, a fairly extensive status report would be presented to the Commission, including recommendations for further proceedings. *Id. at 765:16 – 766:4; TR. 776:4-18 (Kelly).* This timeline permits the process to be informed by the MSP outcomes in PacifiCorp's other jurisdictions.[18]

4. ICNU's Proposed Changes to the Revised Protocol are Unworkable and Unreasonable.

36. ICNU's proposed changes to the Revised Protocol not only embody Mr. Falkenberg's "higher standard" as discussed in Section II above, but suggest that the Commission dramatically depart from traditional cost of service regulation, as described below.

a. Mr. Falkenberg's Proposal to Specially Allocate the Reserve and Load-Following Benefits of the Company's Hydroelectric Resources Is Unreasonable.

37. There are three principal reasons that it would be inappropriate to provide for a special allocation of hydro load following and reserve benefits to Washington under either the Protocol or the Revised Protocol:

1. The Protocol and the Revised Protocol describe methods for allocating costs, not "benefits." *Exh. No. 110 at 23:2-19 (Duvall).*

2. It would be unreasonable to provide for a special allocation of benefits arising from one category of resources, while ignoring "benefits" derived from other resource categories.[19]

[18] The results presumably would be incorporated in the Company's next general rate case, which is expected to be filed during 2005. *TR. 211:19-212:2 (Furman)*; *TR. 330:6-9 (Omohundro)*.

[19] Under either the Protocol or the Revised Protocol, Utah customers pay a disproportionate share of the costs of thermal plants, which also provide ancillary benefits to the system such as Automatic Generation Control. Yet Mr. Falkenberg is not proposing a special allocation of these benefits. *Exh. No. 110 at 23:11-17 (Duvall)* Furthermore, if the MSP became a contest of "interjurisdictional benefit allocation," there is a broader argument available to Utah parties. If one assumes that the hydro resources are being used to provide service to customers in the Northwest, it might be concluded that sales for resale (particularly on the eastern side of the Company's system) are being made from thermal resources. Since Utah customers are supporting a disproportionate share of the costs of such thermal resources, might they not reasonably claim a disproportionate allocation of special sales revenues instead of the system allocation provided for in the Protocol and the Revised Protocol?

3. Finally, if an attempt were made to allocate "benefits" under the Revised Protocol, their valuation would be highly subjective and agreement among MSP participants would be that much harder to achieve. In a complex integrated system like PacifiCorp's, all resources provide value to the system, but that value is dependent upon the presence of other resources in the system. *Exh. No. 110 at 24:7-11 (Duvall); TR. 778:1-14 (Kelly).*

b. Mr. Falkenberg's Proposal to Deal with "Cost Shifts" from Faster Load Growth in Utah is Unnecessary.

38. Mr. Falkenberg correctly observes that neither the Protocol nor the Revised Protocol provides "structural protection" from cost shifts to Washington customers from faster load growth in Utah under all circumstances. *TR. 778:15-22 (Kelly).* In PacifiCorp's view, however, it is appropriate for the Commission to consider the "load growth" issue only in a broader context, with reference to the following considerations:

(i) <u>MSP Studies Demonstrated That Cost Shifts to Slower-Growing States Are Not an Inherent Consequence of a Rolled-In Allocation Method.</u>

39. With some exceptions, both the Protocol and the Revised Protocol rely upon a "Rolled-in" allocation method for new resource additions. A Rolled-in allocation method causes the revenue requirement of faster-growing states to increase. That is because, under a Rolled-in allocation method, a faster-growing state supports both its allocated share of any new resource additions and a larger share of the Company's existing costs. Correspondingly, slower-growing states support an allocated share of the cost of new resource additions, but a smaller share of the Company's existing costs. *Exh. No. 101 at 17:6-11* (*Duvall*); *Exh. No. 303 at 7:9-21* (*Taylor*).

40. The MSP analyses show that in order for costs to be "shifted" to slower-growing states under a Rolled-in method, in addition to requiring that loads consistently grow faster in one state than in others, two other conditions must be met: (a) the cost of new resources must be in excess of the average cost of existing resources[20] and (b) there must be a mismatch of the dispatch

[20] In this context, "the average cost of existing resources" includes system costs that are functionalized to both production and transmission plus associated overheads.

characteristics of the new resource being added with the shape of the new load being served. *Exh. No. 110 at 5:1-11 (Duvall).* It is neither sensible nor equitable to evaluate the Protocol or the Revised Protocol on the assumption that these three conditions will always be met, or that circumstances that have existed for the last few years are necessarily indicative of the future. Specifically:

1. While Utah loads are currently forecasted to grow at a higher rate than other states, load forecasts often prove to be inaccurate. Many debacles in the history of the electric utility industry have resulted from assumptions that recent load-growth patterns are indicative of the long-term future.

2. When Utah is growing faster than other states, but new resources are less expensive than existing resources, costs are "shifted" to Utah and Washington's revenue requirement is lowered as a result.

3. A number of MSP studies demonstrated that if the Company's resource planning is particularly effective and there is a precise match of new resources to load, the faster-growing state incurs a revenue requirement increase substantially *greater* than the cost of the new resources that are added and is burdened with a "cost shift." *TR. 785:13-20 (Kelly).* That is the reason for the finding that, depending upon the assumptions used, the "growth state" would support between 86 percent and 127 percent of the cost of its load growth. The analyses that produced percentages above 100 percent (in which costs are shifted to faster-growing states) are all those in which there is a good match between new resources and loads. *Exh. No. 110 at 8:7-22 (Duvall); TR. 778:23 – 779:5 (Kelly).*

(ii) <u>Elements of the Protocol and the Revised Protocol That Deviate from a Pure Rolled-In Method Further Mitigate the Potential for a Cost Shift from Load Growth.</u>

41. A major concern of Washington parties during the MSP was that new resources being added in Utah were required by Utah's growing summer peak load. Both the Protocol and the Revised Protocol provide for a special allocation of the costs of Seasonal Resources, which are acquired in large measure to meet peak loads. This provision better reflects the seasonal peaking differences of the different states and affords Washington customers protection from summer peak load growth in Utah. *Exh. No. 71 at 8:13 – 9:6* (*Kelly*). However, it is noteworthy that Washington is the second-fastest growing state in the Company's system and is contributing materially to the Company's summer peaking requirements. *TR. 780:2-4* (*Kelly*); *Exh. No. 303 at 6:15-17* (*Taylor*).

(iii) Factors Other Than Any State's Load Growth Substantially Contribute to the Company's Need for New Generating Resources.

42. One of the underlying tenets of both the Protocol and the Revised Protocol is that all states bear a rolled-in share of resources that are acquired to replace existing resources. Existing resources that will require replacement over the next several years include expiring long-term wholesale contracts (primarily on the West side of the system), plant retirements, and the lost generation from Hydro-Electric Resources and Mid-Columbia Contracts as a result of relicensing and contract negotiations. *TR. 779:6-13 (Kelly).*

43. Notwithstanding its expected slower load growth, new resource requirements on the Western side of PacifiCorp's system are substantial and not inexpensive. It is notable that because of these requirements, under the Hybrid method, which largely insulates the states in the West from the effects of Utah load growth, power costs grow *faster* for the Western states than they do under a rolled-in method. *Exh. No. 101 at 18:9-19:2 (Duvall).*

(iv) It Is Not Sensible to Consider the Load Growth Issue Independent of the Benefits to Washington Customers from a Rolled-in Allocation Method.

44. A Rolled-in method provides diversity and a "shock absorber" that protects customers in all states from extreme or unexpected outcomes. For example, when a state loses load unexpectedly, other states are automatically allocated a greater share of all resources. *Exh. No. 110 at 9:17-20 (Duvall).*

(v) Whatever Cost Shift to Washington Is Projected to Occur Under the Protocol Is Not Material During the Period That the Rates Established in This Proceeding are Projected to Be in Effect.

45. As indicated in Section III.C.4.c above, the calculations relied upon by Mr. Falkenberg in raising the "cost shift" issue indicate that there is no cost shift to Washington in 2005 and an apparent $403,000 *benefit* to Washington consumers from faster Utah load growth in 2006. *Exh. No. 420C at 1.*

46. Notwithstanding the foregoing, Mr. Falkenberg proposes that in order to "protect" Washington consumers from costs shifts from faster load growth in Utah, all of the Company's new resource additions should be reflected in rates based upon their short-term market value, rather than cost. While acknowledging that the Commission's long-standing policy has been to establish rates based upon cost, Mr. Falkenberg suggests that that his proposal has precedent in the Commission's 1983 treatment of the Company's interest in Colstrip Unit 3. *Exh. No. 401C at 73:5 – 74:11.* As is apparent from the Commission's 1983 order, *Exh. No. 448*, however, what Mr. Falkenberg described as a "market-based" approach was actually a cost-based one—the referenced Black Hills contract was "based on the fully-distributed costs of Colstrip 3" and, in fact, Colstrip 3 was used as the resource for purposes of calculating costs in the Company's tariff filing for cost-based rates at FERC, *Exh. No. 448 at 8, 15.* Thus the precedent cited by Mr. Falkenberg is inapposite.

47. More importantly, Mr. Falkenberg's proposal would deny Washington customers the benefits of long-term least-cost planning. Faced with the prospect of being able to recover only short-term market prices, rather than cost, no utility would take on the risk of long-term resource commitments. Because PacifiCorp's other states expect the Company to make long-term resource commitments, Mr. Falkenberg's proposal would totally undermine the purpose and benefits of the MSP.

5. Public Counsel's "Hydro Situs" Approach Unrealistically Seizes Inexpensive Hydro Power Benefits for Washington, Includes a Calculational Error Due to a Misunderstanding of the Company's Proposal, and Is Not Worthy of Further Consideration.

48. Mr. Lazar presented his "Washington-centric" proposal that, by allocating all of the Company's hydropower in Washington to the Washington jurisdiction, would produce a $25 million rate reduction for the Company's Washington customers. *Exh. No. 32 at 2:6-10*

(Furman). Under cross-examination, Mr. Lazar was unable to identify any precedent for lower-cost generating resources of a multistate utility being assigned to the state where they are located. *TR. 412:22 – 413:2.* He also based his calculations on a mistaken assumption that the original Protocol involved a simple "roll-in" of hydro costs systemwide, when in fact the original Protocol uses an allocation factor that preserves a "hydro endowment" for the West side, an error that results in an overstatement of his adjustment. *TR. 432:5 – 433:14.* Mr. Lazar also acknowledged that he had no expectation that his proposal would be acceptable to other states and that it would lead to the Company's inability to recover at least $20 million, and perhaps $34 million of costs. *TR. 414:10-19, 415:18 – 419:6.*

D. The Commission Should Adopt the Settlement Proposal Regarding Revenue Requirement.

1. The Settlement Agreement Adopts an Overall Rate of Return of 8.39%, which Falls Reasonably Within the Range Defined by the Company and Staff/Public Counsel Recommendations.

49. A number of issues were in dispute among the parties with respect to cost of capital. The Company requested an ROE of 11.25 percent, supported by the 11.00 percent derived from Dr. Hadaway's analysis, *Exh. No. 41 at 4: -16*, and the additional considerations discussed in Mr. Furman's testimony, *Exh. No. 31 at 2:24 – 6:7.* Staff/Public Counsel witness Hill proposed an ROE of 9.375 percent, *Exh. No. 631 at 5:9-12.* With respect to capital structure issues, Mr. Hill proposed an equity ratio of 44.09 percent, *id. at 32:3-5*, and Mr. Furman recommended 47.08 percent, *Exh. No. 31 at 2:8.* Staff/Public Counsel also proposed to include short-term debt in the capital structure, *Exh. No. 631 at 32:5*, while the Company's proposed capital structure did not price out this component separately, *Exh. No. 31 at 2:6-9.* Overall, the Company proposed a rate of return of 8.743 percent, *id. at 2:9.* Mr. Hill, for his part, recommended an overall rate of return of 7.72 percent on behalf of Staff/Public Counsel, *Exh. No. 631 at 5:13-15.*

50. In the Settlement Agreement, the settling parties were unable to reach agreement on the individual items at issue in connection with the cost of capital. *Exh. No. 1 at 10:9-10.* At the same time, they were able to reach agreement upon an adjustment of approximately $3.5 million to the revenue requirement proposed in the Company's rebuttal case, *id. at 10:10-13*, which is the amount shown in Attachment A to the Settlement Agreement. *Exh. No. 3*. This adjustment, when considered along with the other adjustments in the Settlement Agreement, produces an overall rate of return of 8.39 percent. This recommended overall rate of return falls reasonably within the parameters defined by the Company and Staff/Public Counsel expert testimony (*i.e.*, 8.743 percent at the upper end and 7.72 percent at the lower end).

2. The Settlement Agreement Includes Other Revenue Requirement Adjustments That Should Be Adopted.

51. The Settlement Agreement provides that PacifiCorp will reduce its requested revenue requirement increase by about $10.2 million. *Exh. No. 3 at 5*. This reduces the requested increase from $25.7 million in the Company's rebuttal case to $15.5 million. *Id*. The individual adjustments adopted for purposes of the Settlement Agreement, and their evidentiary support, are set forth in Exhibit A to this Brief.

3. The Remaining ICNU/Public Counsel Adjustments Should Not Be Adopted.

a. ICNU's Proposed Adjustment for Steam Maintenance Expense Should Not Be Adopted.

52. ICNU witness Schoenbeck proposes a reduction in the Company's revenue requirement of approximately $861,000 related to steam maintenance expenses. *Exh. No. 461 at 3:1-4*. Mr. Schoenbeck reached this result by taking the average of four years' maintenance expense, instead of using the Company's fiscal year ("FY") 2003 test year. *Id. at 7:3-4*. The main reason that the four-year period chosen by Mr. Schoenbeck has a lower average steam maintenance expense is that it includes data from calendar year 2000. As can be seen by looking at the total maintenance expense shown in Mr. Schoenbeck's tables, during 2000 the Company's maintenance expenses were approximately 30 to 45 percent lower than during any year since. *Id. at 9: Table*. During cross-examination, Mr. Schoenbeck conceded that the markedly reduced steam plant expenses in

2000 may have been caused by the Company's attempt to minimize power plant outages in response to historically high wholesale power prices of the Western energy crisis. *TR. 147: 15-19.* Mr. Schoenbeck further agreed that the Western energy crisis was a "unique event," and admitted that removing the calendar year 2000 from his average would cause his adjustment to drop significantly. *TR. 147:20-22, 149:2-6.* Therefore, ICNU's adjustment depends not on the use of any four-year average, but on the use of a four-year average that includes data from a unique and extraordinary event—the Western energy crisis of 2000.

53. In addition, Mr. Schoenbeck's testimony ignored several important factors. For example, Mr. Schoenbeck's direct testimony contains a table that purports to show the total and average number of overhaul days for the Company's large thermal power plants. *Exh. No. 461 at 6: Table.* Yet, under cross-examination, the witness acknowledged that the table made no distinction between (i) large power plants vs. small power plants, (ii) old power plants vs. new power plants, or (iii) plants that were fully owned or partially owned by the Company. *TR. 153:13 – 154:10.* Mr. Schoenbeck's failure to consider these factors, as well as others (such as the scope of work performed on each unit), obscures any pattern of scheduled maintenance that might be shown from the underlying data. Further, the table purports to show an average number of overhaul days (303 days), yet the witness admitted that "I cannot sit here today and tell you that we did not double-count that outage," although the witness explained that he "tried to eliminate all the double-counting aspects of maintenance days between the overlapping periods," *TR. 157:2-3, 155:20-22 (Schoenbeck).*

54. The Commission should reject ICNU's proposed adjustment for steam maintenance expenses because (i) ICNU's proposed four-year average is skewed inasmuch as it includes maintenance expense figures from the Western energy crisis, which ICNU's witness conceded was a "unique event," and (ii) the Company's overhaul expenses for FY 2003 were within the range of historical and projected costs for the period 2001-07, as shown by the Company's witness and acknowledged by ICNU's witness. *TR. 147:20-22 (Schoenbeck); Exh. No. 331 at 4:10-11 (Woolley); TR. 152:13 – 153:6 (Schoenbeck).*

b. ICNU's Proposed Adjustments to the Company's Outside Services Expense Should Not Be Adopted.

(i) Snake River Litigation.

55. The Commission should reject ICNU's proposed adjustment related to Snake River legal fees, which is based upon the assertion that the level of such litigation expenses (approximately $1.7 million) was unique and nonrecurring. *Exh. No. 461 at 15:10-11 (Schoenbeck); see also TR. 168:17-19 (Schoenbeck).* ICNU witness Schoenbeck did not dispute that the Company had incurred legal fees of $1 million or more related to a single, distinct matter in the year before and the year after the Company's test year (FY 2003), which would suggest that it was not uncommon for the Company to face one "million dollar" case in a given year. *TR. 168:23 – 169:11.* Indeed, the witness agreed that another such large litigation matter "could happen." *TR. 171:15-19.* Accordingly, the fact that the Company has incurred litigation expenses exceeding $1 million in each of the past three years for three distinct matters suggests that such expenses are not unique and nonrecurring, but in fact happen regularly. Therefore, the Commission should reject ICNU's proposed adjustment.

(ii) MSP.

56. ICNU witness Schoenbeck proposed that the Commission exclude all expenses related to MSP from the Company's revenue requirement. *Exh. No. 461 at 16:8-17.* In his prefiled testimony, Mr. Schoenbeck argued that MSP-related expenses should be excluded because MSP expenses "do not offer any future or ongoing benefits to ratepayers." *Id. at 16:14.* Mr. Schoenbeck's negative view of the benefits of MSP was confirmed during cross-examination:

> Q. Would it be better for [the Company's Washington customers] to have some sort of allocation agreement between the six states than to not have any sort of agreement?

> A. I see more that benefit going to the Company than to the ratepayers. I think---you know, I'll grant you this. I think it would be good that there could be a common allocation methodology among the states, *but I don't know if I'd necessarily translate that into a benefit to Washington ratepayers. . . .* *TR. 163:16-24* (*Schoenbeck*) (emphasis added).
>
> ***
>
> Q. So let me just restate the question. Do the customers---do the Company's customers benefit from having a six-state allocation?
>
> A. I'm not sure about that. *TR. 165:18-21.*

57. In contrast, ICNU's other witness, Mr. Falkenberg, had a more upbeat view of the benefits of MSP to the Company's ratepayers. In support of ICNU's position urging the Commission to adopt a modified version of the Revised Protocol, ICNU witness Falkenberg testified as follows:

> Q. Hypothetically, let's assume that Oregon, Utah, Wyoming and the Idaho Commissions adopt revised protocol along with the various side stipulations in those states. Do you see a benefit in Washington adopting revised protocol in this proceeding?
>
> A. *Well, I think there would be value to the Commission and to the customers if there was an agreement among all states. There is value in that, yes.* *TR. 637:5-13* (*Schoenbeck*) (emphasis added).

Reading the testimony of the two witnesses together, it is apparent that ICNU's witnesses are in conflict regarding the value of MSP. ICNU witness Falkenberg ("There is value . . .") flatly contradicts ICNU witness Schoenbeck ("I don't know if I'd necessarily translate that into a benefit to Washington ratepayers . . . ."). However, since Mr. Falkenberg has been more closely involved with MSP than Mr. Schoenbeck, his view regarding the value of MSP should be afforded more weight than Mr. Schoenbeck's. Moreover, any testimony from ICNU that MSP (and the expenses incurred to develop it) does not benefit the Company's Washington customers must be reckoned with ICNU's position urging the Commission to adopt a modified version of the Revised Protocol in this proceeding. Finally, as noted earlier, this treatment would appear to be contrary to the Commission's order in Docket No. UE-020319, which found that "informal multi-state discussions may be useful to address the interjurisdictional allocation issues" and "participation is in the public interest."[21] For these reasons, the Commission should reject ICNU's proposed adjustment regarding MSP costs.

(iii) RTO.

58. Costs associated with participating in the RTO have been removed from the Company's revenue requirement under the Settlement Agreement. *Exh. No. 3, Att. A.* Mr. Schoenbeck agreed under cross-examination that the adjustment for RTO expenses under the proposed settlement exceeded ICNU's own adjustment, therefore effectively adopting ICNU's adjustment for RTO expenses. *TR. 160:21-25.*

(iv) Hive Down.

59. Mr. Weston's rebuttal testimony explained, and Mr. Schoenbeck's testimony did not dispute, that costs related to "hive down" were in fact MSP costs. *Exh. No. 204 at 8:21 – 9:12 (Weston); TR. 161:7-17 (Schoenbeck).* Mr. Schoenbeck identified approximately $381,000 on a Total Company basis of MSP costs that were labeled as "hive down." *Exh. No. 461 at 17:6-7.* The Commission should not deny the Company recovery of these prudently incurred expenses on the basis of ICNU's testimony that these do not benefit Washington customers, especially when ICNU is simultaneously urging the Commission to adopt a modified version of the Revised Protocol. *TR. 636:20 – 637:13 (Falkenberg).*

[21] It should be noted that among the costs that Mr. Schoenbeck proposes to disallow are travel expenses of various participants—including ICNU—that were reimbursed by the Company to enable participation in the MSP discussions. *Exh. No. 73 at 18:16-19 (Kelly).*

(v) Personal Income Tax Fee And Payments.

60. ICNU witness Schoenbeck proposed a reduction of the Company's test year expenses by $177,000 for tax preparation expenses. *Exh. No. 461 at 21:4-5.* These tax preparation expenses include amounts incurred in preparing tax returns for international assignees. *Exh. No. 371 at 9:5-14* (*Wilson*). The Company pays for these expenses to ensure that the employee and the Company are in compliance with the tax and social security requirements of both the home and host country's governments. *Id.* It is essential that the Company have counsel on taxation of assignment income and benefits because taxes owed and paid by or on behalf of the employee have a direct bearing on the Company's reporting of income earned, and therefore the Company's associated tax payments. *Id.*

(vi) Accounting: Corporate and Nonregulated.

61. ICNU witness Schoenbeck proposed a downward adjustment of the Company's expenses of approximately $1.3 million on a total company basis related to "Transactional Cost Analysis." *Exh. No. 461 at 19:6-8.* During cross-examination, however, Mr. Schoenbeck admitted that only about $250,000 out of the $1.3 million adjustment was associated with Transactional Cost Analysis.

> Q. Would you agree that about a million dollars of your adjustment does not relate to transactional costs analysis?
>
> A. I'd say to use the phrase as a specific subtotal on PWC invoices for FY '03, *transactional cost analysis is approximately $250,000.* The simplified service cost approach, which had to do with capitalizing versus expensing purposes for corporate taxes, was approximately a million dollars. *TR. 189:7-15* (emphasis added); *see also TR. 185:15-20.*

Thus approximately $1 million of Mr. Schoenbeck's proposed $1.3 million adjustment was related to accounting expenses incurred for professional services related to "simplified service cost." Nowhere in Mr. Schoenbeck's prefiled testimony does he explain or justify an adjustment for "simplified service costs"—indeed his testimony does not even mention such costs. Accordingly, at least $1 million of Mr. Schoenbeck's proposed adjustment should be rejected because it is not supported by competent testimony.

c. *Public Counsel's Proposed Adjustment for Cash Working Capital Has Been Reflected in Large Part in the Settlement Agreement, and a Further Adjustment Is Unwarranted.*

62. Public Counsel witness Dittmer proposed an adjustment to rate base for cash working capital based on his analysis of certain components of the Company's lead lag study. *Exh. No. 521 at 20:7-9*. In the Company's rebuttal testimony, Mr. Weston made an adjustment to rate base for cash working capital to reflect the results of an updated lead lag study completed by the Company in March 2004. *Exh. No. 205 at 15:20 – 17:2*. These updates shortened the revenue receipt lag by 6.6 days, in contrast to the 13.7 day reduction proposed by Mr. Dittmer. *Id. at 16:19-22*. The Company's adjustment in its rebuttal case thus incorporated that portion of Mr. Dittmer's adjustment that appears warranted based on a more recent lead lag study.

63. Notwithstanding the Company's adjustment in its rebuttal case, the Settlement Agreement includes a second adjustment for cash working capital that reduces the Company's revenue requirement by an additional $622,000. *Exh. No. 3 at Att. A*.

d. *Public Counsel's Proposed Adjustment for IRS Settlement Payments Has Been Reflected in Large Part in the Settlement Agreement, and a Further Adjustment Is Unwarranted.*

64. Public Counsel witness Dittmer recommended an adjustment disallowing IRS tax settlement payments made during the Company's test year. *Exh. No. 521 at 28:7-11*. The effect of the Settlement Agreement—as was acknowledged by Mr. Dittmer during cross-examination—was to remove approximately 50 percent of the amount that the Company was seeking to recover for tax settlement payments made during the test year. *Exh. No. 3 at Att. A; TR. 714:21-24 (Martin), TR. 750:14-16 (Dittmer)*.

65. Assuming that the Settlement Agreement is adopted, assigning fifty percent of the tax settlement payment expense to shareholders is a reasonable compromise between all parties. Nevertheless, recovery of the remaining 50 percent of the tax settlement payments under the Settlement Agreement is appropriate because such payments were a part of the Company's cost of service during its test year and reflect an ongoing, recurring expense incurred in providing service to the Company's Washington customers.

66. Mr. Dittmer, however, argues that the Company should not be able to recover any of its tax settlement payments because the Company has not specifically identified these tax settlement payments as being related to Washington retail operations. *Exh. No. 521 at 29:15-17.* This is an impossibly high standard, however, because the total settlement payments payable to the IRS are calculated on an entity-level basis, making it very difficult to allocate such payments on a state-by-state basis. *Exh. No. 283 at 2:18-22* (*Martin*). It is for this reason that the Company's Interest-Before-Tax approach is a fair and reasonable method that accurately reflects Washington's share of the Company's tax settlement expense. *Id.*

67. Mr. Dittmer raised another concern in his testimony related to the "normalization" of the Company's tax expense. *Exh. No. 521 at 30:10 – 36:15.* While the Company generally agrees with Mr. Dittmer's statement of the principle, Company witness Martin explained in his rebuttal testimony and during the hearing that these expenses had not yet been funded by the Company's Washington customers. *Exh. No. 283 at 4:17 – 5:5; TR. 711:5-12.* Therefore, it is appropriate that the Company recover its tax settlement payments since the cost of the tax settlement expenses has not been normalized or otherwise previously recovered through rates.

e. Public Counsel's Proposed Adjustment to Miscellaneous Deferred Debits and Regulatory Assets Should Not Be Adopted.

68. Public Counsel witness Dittmer proposed an adjustment to reduce rate base by $7,610,360 to remove various deferred debits and regulatory assets. *Exh. No. 521 at 22:19 – 27:14*; *Exh. No. 527: Schedule B-4 at 1:27.* Mr. Dittmer recommends that the Commission

disallow both regulatory assets and deferred debits for which the Company has not yet received a deferral authorization from the Commission. *Exh. No. 521 at 23:14-16.* This adjustment is incorrect with respect to deferred debits because it fails to distinguish between the applicable regulatory requirements. Where Commission approval is required, as for the creation of a regulatory asset, the Company follows the required process. With respect to regulatory assets, Mr. Weston's rebuttal testimony explains why the Trail Mountain costs and environmental remediation costs should not be excluded. *Exh. 204 at 23:15 – 24:20; Exh. 207.* In the case of deferred debits, expenses in many cases are required to be capitalized, in accordance with GAAP, in order to comply with the matching principle. Mr. Weston's rebuttal testimony itemizes each of these deferred debits, and demonstrates how the assets have benefited customers over multiple periods and thus are appropriately amortized over the same period. *Exh. 204 at 17:15 – 23:14; Exh. 207.* Mr. Dittmer's exclusion of deferred debits ignores this matching principle, and should be rejected.

69. Further, Mr. Dittmer acknowledged in his testimony that his adjustment should be reduced by any related Miscellaneous Deferred Credits or amortization credits. *Exh. No. 521 at 27:7-14.* One such credit that was not included in Mr. Dittmer's adjustment relates to environmental settlement funds that are in an account titled Environmental Deferred. *Exh. No. 203 at 8.1.* PacifiCorp received these funds under an insurance settlement for environmental clean-up projects. *Id.* As the Company expends funds on clean-up costs, the balance of this fund is amortized. *Id.* During cross-examination, Mr. Dittmer agreed that any related deferred credit that had not been considered should be included. *TR. 749:1 – 750-1.* Therefore, since the environmental settlement funds are used to offset the Company's deferred environmental liabilities, and Mr. Dittmer has proposed to remove Miscellaneous Deferred Debits that include the Company's environmental liabilities, *see Exh. No. 527: Schedule B-4 at 1:10*, it is appropriate to remove the associated credit for those clean-up expenses. Mr. Dittmer's adjustment is thus overstated by $1,854,370. *Exh. No. 203 at 8.1.*

E. The Commission Should Adopt the Settlement Proposal Regarding Net Power Costs

1. The Settlement Agreement Reflects Annual Net Power Costs of $534 Million, Which Includes Many of the Adjustments Offered by ICNU Witness Falkenberg.

70. The Company's rebuttal filing proposed annual net power costs of $555.0 million. *Exh. No. 137 at 2:12* (*Widmer*). ICNU, for its part, proposes annual net power costs of $500.1 million. *Exh. No. 401C at 2, Table 1* (*Falkenberg*). The Settlement Agreement adopts an annual net power cost figure of $534.1 million. *Exh. No. 3 at Att. B.* Thus the gap between the Company's case and ICNU's position has been closed by nearly 40 percent. *TR. 556:8-11 (Falkenberg).* Moreover, the Settlement Agreement adopts $5.9 million of Mr. Falkenberg's adjustments,[22] in addition to the $7.5 million of Mr. Falkenberg's adjustments reflected in Mr. Widmer's rebuttal testimony. *Exh. No. 3 at Att. B.* As a basis for opposing the Settlement Agreement, Mr. Falkenberg urges adoption of all his remaining adjustments, which would produce annual net power costs of $500.1 million.

71. This $500.1 million figure is substantially below any number within the Company's recent actual experience. Power costs for the 12 months ended March 2004 were $646 million. *TR. 557:11-14* (*Falkenberg*). Power costs for the 12 months ended May 2004 were $687 million. *Exh. No. 137 at 17:21-23* (*Widmer*). Forecast net power costs for the 12 months ended March 2006 are expected to be in excess of $745 million. *Id. at 17:23 – 18:1.* While Mr. Falkenberg claims that power costs have "declined" from their previous levels, his point of reference—as indicated on Exhibit 430 at 4—is the $1.2 billion incurred by the Company during the Western energy crisis. *TR. 558:2-10.* Mr. Falkenberg's own exhibit shows that on a rolling 12-month basis, the lowest figure he can demonstrate is $598 million, the Company's actual power costs for calendar year 2003. *Exh. No. 430 at 4.* This figure is 20 percent higher than the $500.1 million figure urged by Mr. Falkenberg. While power costs have obviously declined

[22] These adjustments comprise the following: Aquila hydro hedge ($1.75 million), J. Aron temperature hedge ($2.1 million), Morgan Stanley temperature hedge ($1.8 million), and CT dispatch ($228,000).

from the unprecedented and extraordinary levels experienced during the Western energy crisis, they are clearly headed in an upward direction, and Mr. Falkenberg's proposed $500.1 million figure is inconsistent with that undisputed reality.

2. The Settlement Agreement Reflects Several Adjustments to the Company's Proposed Net Power Costs.

72. As noted above, the Settlement Agreement provides that PacifiCorp will reduce its filed net power costs from $555 million on a Total Company basis (as stated in the Company's rebuttal case) to $534.1 million. The individual adjustments adopted for purposes of the Settlement Agreement reduce the Company's annual net power costs by $20,876,709, which is about $1.93 million on a Washington-allocated basis. These individual adjustments and their evidentiary support are set forth in Exhibit B to this brief. In addition, the Company's rebuttal testimony included several updates, corrections, or adjustments to net power costs, including adoption of several adjustments proposed by ICNU witness Falkenberg listed in Exhibit B.

3. The Remaining Adjustments Proposed by ICNU Witness Falkenberg Should Not Be Adopted.

a. Mr. Falkenberg's Entire Analysis Suffers from Application of an Incorrect Standard.

73. As discussed in Section II above, ICNU witness Falkenberg claimed in response to a data request that

> a very high standard of proof should be required of the Company in this case on all issues because it represents an early exit from the rate plan. Given this, the Company should be held to a very high standard. *Exh. No. 437 at 1.*

According to Mr. Falkenberg, he applied this "very high standard" throughout his analysis of the Company's power supply issues. *TR. 560:1-5.* For the reasons set forth in Section II above, this flawed premise affects the validity of Mr. Falkenberg's entire analysis of the Company's power supply issues. It is not apparent, for example, how his analysis would have differed had a correct, "unheightened" standard been applied. Presumably, some adjustments would not have been offered. Some adjustments may have been offered, but their magnitude may have changed. With respect to outages in particular, Mr. Falkenberg noted that "a very high standard of proof should be required in the case of outage rate modeling." *Exh. No. 401C at 34:9-10.* Given that Mr. Falkenberg's outage adjustments were the largest in his analysis—comprising over $14.1 million on a Total Company basis—the effect of this false premise, at a minimum, should be to cast a doubt upon the validity of a substantial portion of Mr. Falkenberg's analysis.

b. Short-Term Transactions: The Proposal to Include BPA Settlement Power in Net Power Costs Should Be Rejected.

74. Although the regulatory treatment regarding this issue is in dispute, the underlying facts are not. Between November 16, 2000 and April 4, 2001, PacifiCorp mistakenly delivered power to BPA because of a faulty meter owned by BPA. As a result of a settlement, BPA agreed that it would deliver 41,600 MWh of short-term firm energy back to PacifiCorp in July and August 2003, and 21,600 MWh in October 2003. *TR. 572:4-14 (Falkenberg).* Mr. Falkenberg proposes to include these energy deliveries in the calculation of annual net power costs, which represents a $6.9 million adjustment on a Total Company basis.

75. This adjustment should be rejected. First, it is clear that these power deliveries from BPA are nonrecurring, and instead represent an isolated transaction comprising the "flipside" of the mistaken power deliveries from PacifiCorp to BPA in 2001. *Exh. No. 137 at 18:23 – 19:2* (*Widmer*). Mr. Falkenberg admits that BPA cannot be expected to routinely deliver free power to PacifiCorp on a going-forward basis, *TR. 572:20-23*, and that the delivery of free power from BPA is not a typical short-term firm transaction, *id. at 573:21-23.* Second, the reference cited by Mr. Falkenberg as additional basis for including these deliveries—that the Company made an adjustment for them in Oregon—is completely inapposite. *Exh. No. 401C at 10:17-19.* While it is true that as part of the settlement in Docket UE 147 the Company agreed to provide a credit against the power cost deferral that it was allowed to collect from Oregon customers, that is because Oregon customers—through the deferrals authorized in Docket UM 995—***actually***

incurred the costs associated with the mistaken power deliveries to BPA. Exhibit 446 is the document establishing the basis for the inclusion of a credit. That document indicates that the mistaken power deliveries to BPA occurred during the Deferral Period in that proceeding—November 1, 2000 through September 7, 2001—and thus the $130 million in excess net power costs borne by the Company's Oregon customers included the impacts of those deliveries. It was therefore necessary and appropriate that these customers correspondingly receive the benefits of the "free" power deliveries that BPA agreed to make in return in July, August, and October 2003. The agreement included as Exhibit 446 assigns a value to these power deliveries, and provides a credit against the UM 995 deferrals to reflect that value. Mr. Falkenberg concedes that the Company's Washington customers did not similarly bear the costs associated with the mistaken BPA power deliveries. *TR. 576:18-23.*

76. Mr. Falkenberg's adjustment is based on the premise that because the Rate Plan was modified to permit this general rate filing, the Company's Washington customers did in fact "pay for higher power costs during the power crisis." *Exh. No. 401C at 13:3-4, 12:4-6.* Mr. Falkenberg admits, however, that this general rate case filing does not seek, and the Company would not be permitted, to reach back and recover costs incurred during the Western energy crisis. *TR. 577:19-23.* Moreover, his reading of the Commission's Deferred Power Cost Order mistakenly concludes that the impact of the Western energy crisis upon the Company was the sole basis for modifying the Rate Plan to permit this general rate filing. Although the order speaks for itself, the Commission cited a number of factors, including the apparent failure of the Company to meet its burden, *Deferred Power Cost Order* ¶ *22,* the inability to calculate deferrals given the absence of a baseline, *id.* ¶ *25,* and an agreed-upon cost allocation methodology, *id.* ¶ *31,* and the need to ensure accountability going forward, which was "critically important from the Commission's perspective," *id.* ¶ *42.* Mr. Falkenberg's adjustment is based upon a narrow, flawed interpretation of the order, combined with reference to inapplicable precedent from the Company's recent proceedings in Oregon. It should be rejected.

c. ***Long-Term Contract Adjustments.***

(i) The Adjustment Reflecting the "Option Value" of West Valley, Morgan Stanley, and Sempra Should Be Rejected, as Any Optionality Benefits Associated with These Resources Are Captured by Use of Actual Short-Term Firm Transactions in Net Power Costs.

77. The Company made its key acquisitions—including the West Valley units and the Morgan Stanley and Sempra contracts—through an RFP process to secure resources to meet load requirements. Through that process, these resources were determined to be the least-cost options on a risk-adjusted basis and, on that basis, they were acquired. *Exh. No. 137 at 22:9-10 (Widmer).* West Valley, for its part, is a lease contract that allows the Company to call on 200 MW of physical capacity in Utah on a daily basis. *Exh. No. 191 at 6:19-21* (*Tallman*). The Morgan Stanley contract is a 100 MW summer peak capacity contract with an option to take firm energy on a day-ahead basis at a strike price of $55 per MWh. *Exh. No. 137 at 26:9-12* (*Widmer*). The Sempra contract is a 100 MW summer peak capacity contract with an option to take firm energy on a day-ahead basis, at a strike price equal to a set heat rate multiplied by the daily Malin Midpoint gas index plus $0.04 per MMBtu. *Id. at 24:18-22.* The primary purposes of the West Valley, Morgan Stanley, and Sempra contracts are to provide reliability and risk mitigation and to serve peak load requirements on the east side of PacifiCorp's system. *Exh. No. 191 at 8:12 – 9:2* (*Tallman*)*; Exh. No. 137 at 26:11-12, 24:20-22* (*Widmer*).

78. ICNU witness Falkenberg proposes to make an adjustment to reflect the "option value" for these resources. The proposed adjustments—which would reduce net power costs by $3.1 million on a Total Company basis for West Valley, by $2.4 million for Morgan Stanley, and by $800,000 for Sempra—should be rejected. The theory underlying Mr. Falkenberg's adjustment—that GRID fails to capture the "optionality" of these resources—is spurious. In fact, the "option value" of these resources allows the Company to either avoid higher-priced market purchases, serve load when transmission constraints exist, or make additional economic

wholesale sales.[23] The Company's proposed net power costs in this case include actual short-term firm transactions during the period April 2003 through September 29, 2003. *Exh. No. 137 at 23:6-8* (*Widmer*). This period includes the summer peak period covering the Morgan Stanley, and Sempra seasonal contracts and includes the period having the most volatility and option value in the Desert Southwest for purposes of the West Valley resource. *Id. at 23:10-15.* Thus sales made or purchases avoided as a result of the option value of West Valley, Morgan Stanley and Sempra are captured in GRID, contrary to Mr. Falkenberg's suggestion. Adopting the further reductions proposed by Mr. Falkenberg would result in a duplicative reduction for these resource optionality benefits.

79. This was the finding of the Wyoming PSC recently when Mr. Falkenberg proposed the very same adjustments in the Company's 2003 general rate case. According to that Commission's order:

> *The proposed optionality valuation is highly speculative, and the effect of these agreements on power costs is actually captured among the short term firm data included in net power costs in this case.* These options relate directly to actual power resources, giving PacifiCorp valuable flexibility in dealing with their resource needs—especially when those resources may, because of system demands, be most valuable. Some very important system benefits, such as being able to avoid transmission constraints during peak times on the eastern part of PacifiCorp's system, have a value that must be measured in substantial general economic and public safety terms beyond the price of the agreement. *We will not artificially penalize PacifiCorp's efforts to secure and maintain such resources. Exh. No. 447 ¶ 40b, at 21 (emphasis added).*

80. Mr. Falkenberg further notes that these resources were acquired after an evaluation process that, among other things, used Black-Scholes modeling.[24] Based on this, he goes on to

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[23] For example, if the spark spread for gas and electricity improved because electric prices increased and gas prices did not increase in the same amount, the Company would run West Valley at a higher capacity factor so higher-cost market purchases could be avoided or so additional wholesale sales could be made. *Exh. No. 137 at 23:2-6 (Widmer).*

[24] The Company uses Black-Scholes modeling as a tool to value option contracts. When a prospective option owner is deciding whether or not to buy, or a prospective option seller is deciding whether or not to sell, a model must be used to estimate the option value to determine the option price. The price of an option is known as

make the curious argument that the Commission should "consider disallowing the costs of resources selected by the [Black-Scholes] model on the basis of imprudence." *Exh. No. 401C at 16:3-5.* Relying on the fact that the Black-Scholes equations were used extensively by the infamous hedge fund, Long-Term Capital Management ("LTCM"), Mr. Falkenberg draws the curious conclusion that the model is "unproven, novel and highly speculative." *Id. at 15:5-13, 16:3.* Criticizing Black-Scholes on the basis of the LTCM experience is akin to condemning the internal combustion engine on the grounds that automobiles are occasionally involved in accidents. PacifiCorp uses Black-Scholes for several reasons, and has measures in place that distinguish PacifiCorp's circumstances from LTCM. *Exh. No. 351 at 8:6-16* (*Mumm*). In the Company's experience, Black-Scholes has delivered useful, commercially reasonable option values for a wide variety of instruments.[25] Mr. Falkenberg's interjection of Black-Scholes modeling as a backhanded reason for disallowing a portion of these resources should be summarily rejected.

(ii) <u>The Adjustment for the P4 Contract Should Be Rejected as the Challenged System Integrity Provisions of the Contract Provide Benefits for Customers.</u>

81. Mr. Falkenberg proposes to reduce the cost of the P4 contract on the grounds that the system integrity components of the contract cannot be captured in GRID. The proposed adjustment would reduce the Company's revenue requirement by approximately $490,000 on a Total Company basis.

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the option "premium." The Black-Scholes model helps buyers and sellers determine this premium and, later, to determine the ongoing value or "mark-to-market" value of the option. The Black-Scholes model was developed by scholars in an academic framework; as acknowledged by Mr. Falkenberg, one of the authors, Myron Scholes, won a Nobel Prize in economics in large part due to his development of the Black-Scholes option valuation model. For the purposes of option modeling, Black-Scholes is the most common and most credible model. *Exh. No. 351 at 8:6-16* (*Mumm*).

[25] Backtesting Black-Scholes predictions has shown the model's accuracy. Black-Scholes has validated option model quotes from counterparties and has validated published quotes from widely traded option instruments such as the energy commodity options traded on the New York Mercantile Exchange (NYMEX). Finally, Black-Scholes has tremendous credibility in the financial and commodity community. Many software houses and financial and engineering firms have developed standardized derivative valuation software packages, and the most common option valuation model is Black-Scholes. *Exh. No. 351 at 9:6-14* (*Mumm*).

82. This adjustment should be rejected. The system integrity component is just a small portion of the overall contract that provides approximately $11 million of benefits to customers. *Exh. No. 137 at 27:9-10* (*Widmer*). Although the system integrity portion of the contract is not captured explicitly in GRID, this component provides system reliability and risk mitigation by allowing the Company to interrupt P4's operation in the event of a system emergency. *Id. at 27:14-17*. Moreover, it is not reasonable to exclude a particular provision of the contract, when the entire contract produces approximately $11 million of benefits for customers. *Id. at 27:22-23.*

d. Modeling Adjustments.

(i) <u>Market Size Limit: Mr. Falkenberg's Adjustment for Market Size Limit Should Be Rejected as It Suggests a Level of Coal Generation That Is out of Line with Historical Experience</u>.

83. Market caps are used to limit the size of the market during graveyard hours to a realistic size, because the market is not completely liquid in the middle of the night. Without the caps, GRID would allow the coal units to generate more than they actually do. *Exh. No. 137 at 30:12-15* (*Widmer*). Mr. Falkenberg's proposed adjustment would revise the Company's market caps during graveyard hours (1-5 a.m.) Pacific Time to allow more system balancing sales from energy that would be produced by the Company's coal generation. *Id. at 30:3-6*. The proposed adjustment would reduce the Company's net power costs by $9.9 million on a Total Company basis.

84. Mr. Falkenberg's proposed adjustment would produce an excessive level of generation, and should be rejected. The best indicator of whether GRID is producing a reasonable level of coal generation is the total level of coal generation, not the level of generation during only graveyard hours. *Id. at 30:21-23* (*Widmer*). As shown in Table 2 in Mr. Widmer's rebuttal testimony, *id. at 31:10-11*, the level of coal generation resulting from Mr. Falkenberg's adjustment is approximately 45.3 million MWh and exceeds by a considerable amount—approximately 1.2 million MWh—the rolling four-year average for the 48-month period ended

March 2003.[26] On the other hand, the 44.4 million MWh of coal generation included in the Company's proposed net power costs is more consistent with historical coal generation.

85. Mr. Falkenberg's Exhibit No. 410—which he uses to demonstrate the reasonableness of his generation normalization adjustments—includes a number of flaws that render it useless, including the following:

- It relies upon stale data as a starting point—a four-year average ended December 2002 instead of a rolling four-year average ended March 2003 (which would produce average coal generation of 44.1 million MWh) or March 2004 (43.9 million MWh), compared to 45.3 million MWh on Exhibit 410. *Id. at 31:20 – 32:4.*

- Its spinning reserve adjustment is understated slightly using a 48-month period ending March 2003 and overstated by approximately 94,000 MWh for the 48-month period ending March 2004. *Id. at 32:5-7.*

- It improperly reflects several outage adjustments that should be rejected for reasons discussed in Section III.E.3.d(ii) below.

- It incorrectly assumes that other base load coal generation units had unused generation that picked up the portion of Centralia generation not covered by the TransAlta purchase. *Id. at 32:11-18.*

- Its Colstrip 3 adjustment should be 27,930 MWh higher, based on the Company's proposed net power costs. *Id. at 32:19-20.*

- The 1999 market price adjustment would be excluded if the more current four-year rolling average ending March 2004—which is more current and is a better representation of the Company's operation—were used. *Id. at 32:21 – 33:2.*

- It includes coal generation during 2000, which was significantly—and abnormally—higher than the other years due to the extremely high market prices and generation shortages during the Western energy crisis. *Id. at 32:3-8.*

86. Mr. Widmer's Exhibit No. 139 is a corrected version Mr. Falkenberg's Exhibit 410, and includes information for the 48-month periods ended March 2003 and March 2004. The exhibit demonstrates that the Company's modeled coal generation is reasonable and the level of coal generation resulting from Mr. Falkenberg's market cap adjustment is excessive.

Mr. Falkenberg's adjustment should therefore be rejected by the Commission.

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[26] If the actual average is updated to 48 months ended March 2004, his recommendation exceeds the average by 1.4 million MWh. *Exh. No. 137 at 31:3-5 (Widmer).*

(ii) Adjustments for Outages.

87. This issue, also referred to as "thermal deration factors," concerns the methodology for incorporating a normal level of outages in the Company's normalized net power costs. For purposes of determining the thermal deration factors, the Company uses a compilation of outages over the most recent historical period (in this case, April 1999 through March 2003). The dispute on this issue concerns whether this four-year rolling average should be adjusted to exclude certain major, catastrophic outages or whether the "unadjusted" four-year rolling average should be used. Mr. Falkenberg's position is that the four-year rolling average should be adjusted to exclude certain "catastrophic," "unusual," or "imprudent" outages. *TR. 580:4-6.* The Company maintains that the unadjusted average should be used. *Id. at 580:7-11.*

88. The position taken by Mr. Falkenberg in this proceeding is directly at odds with his recommended treatment of this issue in the same circumstances. In the Company's 2002 Wyoming general rate case, Wyoming PSC Docket No. 20000-ER-02-184, the Company had proposed to exclude a number of outages in calculating the four-year rolling average. Mr. Falkenberg opposed these exclusions, testifying as follows:

> In the past, the Company computed outage rates for thermal plants using the simple four-year rolling average with no other adjustments for catastrophic or abnormal outages. Consequently, outage costs, such as those related to the Hunter Unit 1 failure, were recovered by recognizing an increase in plant outage rates. This procedure effectively allowed for a four-year amortization of major outage. While it did not provide an exact matching between actual outage costs and subsequent recovery, it was a balanced and beneficial approach. It afforded the opportunity to reflect outage cost impacts in customers' rates, while at the same time creating an incentive for PacifiCorp to minimize the cost and duration of all outages. *TR. 581:21 – 582:10* (*Falkenberg*).

In that case, Mr. Falkenberg recommended that "the Commission revert back to the unadjusted four-year rolling average calculation, not only for Hunter, but for all plants." *TR. 583:22-25.* The Wyoming Commission adopted Mr. Falkenberg's recommendation, and an unadjusted four-year rolling average was used for purposes of setting rates in that proceeding, as well as in the subsequent general rate proceeding in Wyoming. *Id. at TR. 590:16-20, 591:20-24.*

89. In this proceeding, Mr. Falkenberg proposes to depart from that recommended treatment. In doing so, he recommends a series of adjustments that would exclude various outages from the four-year rolling average, the cumulative effect of which is to reduce net power costs by about $14.1 million on a Total Company basis. *Exh. No. 401C at 2, Table 1.* For all the reasons stated by Mr. Falkenberg in his Wyoming testimony above, the unadjusted four-year rolling average should be used, consistent with the practice in all the Company's jurisdictions with litigated rate cases during the past 10 years. *Exh. No. 137 at 34:2-8* (*Widmer*).

(a) Hunter 1 Outage

90. By far the largest outage proposed to be excluded by Mr. Falkenberg is the Hunter 1 outage, which occurred during the height of the Western energy crisis, from November 2000 through early May 2001. *TR. 585:8-13* (*Falkenberg*). This adjustment alone amounts to $7.7 million on a Total Company basis. The reasons given by Mr. Falkenberg to support his adjustment, however, are flawed and fail to support adoption of the adjustment.

91. First, Mr. Falkenberg cites the Company's general rate case filings in other states, where the Hunter 1 outage was excluded from the four-year rolling average. *Exh. No. 401C at 35:6-9.* As established during cross-examination, however, the Company excluded the Hunter 1 outage from its most recent Oregon rate case (UE 147) and its most recent Utah rate case (Docket No. 03-2035-02) *because these commissions provided separate recovery for the Hunter 1 outage through a different regulatory mechanism (deferred accounting).* The Company's Oregon customers are paying $130 million in extraordinary power costs in UM 995—which include the impact of the Hunter 1 outage—and the Company's Utah customers are paying $147 million in extraordinary power costs in Docket Nos. 01-035-23, -29, and -36 (Report and Order issued May 1, 2002), which similarly includes the impact of the Hunter 1 outage. *TR. 589:16-24*

(*Falkenberg*). In these circumstances—where a separate recovery of the outage impact has been provided—it would be a double recovery for the Company to seek to include the Hunter 1 outage in the four-year rolling average, as Mr. Falkenberg conceded. *Id. at TR. 589:4 – 590:9.* As noted by Mr. Falkenberg, the Company also excluded Hunter 1 from its 2002 Wyoming rate case. *Exh. No. 401C at 35:8-9.* This is because the Company sought to recover the impacts associated with the Hunter 1 outage through a separate surcharge, a request that was denied by the Wyoming Commission. Instead, the Wyoming Commission adopted Mr. Falkenberg's recommendation—at least his recommendation at that time—to include recovery of the Hunter 1 impacts as part of the four-year rolling average, as noted above.

92. Second, Mr. Falkenberg contends that the Company's Washington customers, similar to its customers in Utah and Oregon, in effect "paid" for the impacts of the Hunter 1 outage, given that "a major reason this case is even taking place is because of the power crisis, which was most certainly exacerbated by the Hunter Unit 1 outage." *Exh. No. 401C at 35:18-23.* The Company's Washington customers were shielded from the impacts of the Hunter 1 outage, in contrast to the $130 million recovery of deferred power costs in Oregon and $147 million of deferred power costs in Utah. Moreover, for the same reasons as stated in Section III.E.3.b above with respect to the BPA Settlement, it is a mischaracterization of the Deferred Power Cost Order to claim that the decision to amend the Rate Plan to permit this filing is attributable to the Hunter 1 outage.

93. Finally, Mr. Falkenberg suggests that inclusion of the Hunter 1 outage in the thermal deration modeling "assume[s] that the Hunter Unit 1 outage would recur once every four years." *Exh. No. 401C at 34:22-23.* This is somewhat misleading, as the impact of the Hunter 1 outage was estimated at $270 million, since it occurred at the absolute height of the Western energy crisis. *Exh. No. 137 at 37:4-9* (*Widmer*)*; TR 588:6-10* (*Falkenberg*). Moreover, this rationale offered by Mr. Falkenberg is completely at odds with his endorsement of the unadjusted four-year rolling average that, as he stated, is "a balanced and beneficial approach" that "creat[es] an incentive for PacifiCorp to minimize the cost and duration of all outages." *TR. 581:21 – 582:10.* Mr. Falkenberg's proposed adjustment for the Hunter 1 outage should be rejected.

(b) CT Outages.

94. In its modeling for the Gadsby and West Valley CTs, the Company used the actual historical outage rates incurred since the units were placed in service plus assumed mature outage rates for the remainder of the four-year period because the units have not been in operation for four years. The impact of the Company's modeling was to reduce the outage rates below actual historical operation. *Exh. 137 at 38:8-12* (*Widmer*). Mr. Falkenberg proposes to use the mature outage rates for the Gadsby and West Valley CTs instead of using the actual normalized outage rates proposed by the Company. His proposed adjustment would reduce the Company's net power costs by $700,000 on a Total Company basis. *Exh. No. 401C at 37:3-21* (*Falkenberg*).

95. No basis has been demonstrated for this adjustment, as the Company's operation of these plants compares favorably with industry statistics. *Exh. No. 137 at 38:17-18* (*Widmer*). The Company's average actual forced outage rate for these units was 17.79 percent through March 2003, while industry data for the period 1999 through 2002 was 18.61 percent. *Id at 38:18-20.* Moreover, the performance of these units has continued to improve—the average actual outage rates through March 2004 was 11.61 percent, and the Company modeling reflects outages at a still lower rate of 8.58 percent. *Id. at 38:21 – 39:1.* This adjustment should be rejected.

(c) Other "Catastrophic" or Abnormal Outages.

96. Mr. Falkenberg also proposes to exclude as "catastrophic" or "unusual" the outages at Dave Johnston 3, Hayden 1, and Colstrip 4. *Exh. No. 401C at 41:13-16.* The Blundell deration is also proposed to be excluded for the reason "that the Company's modeling assumes the problem was never solved and will continue to recur." *Id. at 40:22 – 41:1.* Exclusion of these outages is inconsistent with the purpose of using a four-year rolling average, which is not to

presume recurrence of a particular outage but to capture a representative level of outages for ratemaking purposes. *Exh. No. 137 at 39:17-20* (*Widmer*).

(d) Outages Due to Personnel Errors.

97. Mr. Falkenberg proposes to exclude a number of other outages due to claimed imprudence or personnel errors. These include the outages at Jim Bridger Unit 4, *Exh. No. 401C at 38:3-27* (*Falkenberg*); Hunter Unit 3, *id. at 41:4-10*; and other outage incidents reported as "operator errors," "maintenance errors," "subcontractor errors," or "other safety problems," *id. at 42:5-25*. As indicated in Mr. Woolley's rebuttal testimony, the Company does not agree that it admitted to imprudence in connection with the Jim Bridger Unit 4 outage, *Exh. No. 331 at 7:1-5*, nor that the Hunter Unit 3 outage was due to imprudence, *id at 9:9 – 10:3*. Moreover, the fact that personnel errors occasionally occur does not demonstrate imprudence. *Id. at 7:10-11.* Rather, imprudence would be demonstrated by a failure to implement adequate training, good procedures, or continuous emphasis on safety, or to investigate failures. *Id. at 7:11-21.* In this regard, PacifiCorp has a favorable record with respect to outages arising from personnel errors, as compared with other utilities. *Id. at 8:14 – 9:5.*

98. Moreover, on a broader view, the Company's equivalent availability factor and capacity factor are significantly better than the industry averages. Thus, even after taking into account the "unusual," "nonrepresentative," or "catastrophic" outages that Mr. Falkenberg proposes to exclude, the Company is able to achieve a higher than average utilization of generating assets, as indicated by the table on page 10 of Mr. Woolley's rebuttal testimony. *Id. at 13:6-10.*

(iii) Gas Plant Heat Rate Modeling: The Company's Rebuttal Testimony Includes a $1.57 Million Adjustment to Update the West Valley Heat Rates, and No Further Adjustment Is Necessary.

99. The heat rate curves for Gadsby Units 4-6 and West Valley Units 1-5 were developed based on data from the manufacturer, General Electric ("GE"). *Exh. No. 137 at 42:17-20* (*Widmer*). PacifiCorp used the data provided by GE to estimate the net unit heat rates based on delivery of electricity to the high side of the generator step-up transformers and the higher heating value of natural gas. *Id. at 42:20 – 43:2.* Mr. Falkenberg claims that the Company's modeling substantially overstates the heat rates compared to actual heat rates shown in the Company's 2002 FERC Form 1. *Exh. No. 401C at 47:13-20.* His proposed adjustment would reduce the Company's originally filed net power costs by $3.19 million on a Total Company basis.

100. When the Company reviewed the performance of these CT units based on actual operation, the Gadsby heat rate at maximum availability was demonstrated to be consistent with the level originally projected. *Exh. No. 137 at 43:3-7* (*Widmer*). The West Valley heat rate at maximum availability, however, was 5 percent lower than projected. The Company therefore included a modeling adjustment correction in its rebuttal case, which reduced net power costs by $1.57 million on a Total Company basis. *Id. at 43:9-11.* Mr. Falkenberg continues to maintain that an adjustment for both West Valley and Gadsby is warranted, notwithstanding this correction made by the Company. According to Table 2 in his responsive testimony, this adjustment was valued at $285,477 on a Washington-only basis. *Exh. No. 401C at 7:18.* In his supplemental testimony, he continues to carry this adjustment as "still in dispute," and values it at $271,225 on a Washington-only basis, *Exh. 425*, which clearly fails to reflect the significant adjustment incorporated in the Company's rebuttal case.

101. In the Company's view, the West Valley heat rate error has already been corrected in the Company's updated net power costs, and Gadsby heat rates are consistent with actual operation. *Exh. No. 137 at 43:19-22* (*Widmer*). Therefore, no further adjustment is necessary and Mr. Falkenberg's proposed adjustment should be ignored.

e. ***Non-Power Cost Issues.***

(i) ICNU's Adjustment to Reduce the Gadsby Rate Base Investment Is Based upon a Contrived "Conflict of Interest" Theory, and Should Be Rejected as Inconsistent with the Facts and Accounting Principles.

102. ICNU witness Falkenberg proposes that the Company's investment in the CTs at Gadsby be reduced by $7.5 million. Mr. Falkenberg's adjustment is based upon the novel theory that a cost that the Company is able to avoid in one transaction—the avoidance of CT lease payments to GE—should become an offset in a totally separate transaction—the rate base investment associated with the Gadsby CTs.[27] According to Mr. Falkenberg, such an adjustment is necessary to ensure that ratepayers are not harmed by the Company's "conflict of interest" during the negotiations with GE. *Exh. No. 401C at 48:11-14.* This adjustment should be rejected for at least four reasons:

- It assumes a fictional negotiation that did not in fact occur. The adjustment assumes that the Company was given a choice of the form in which to take the $7.5 million savings offered by GE, and there is no evidence whatsoever to support this assumption. *TR. 593:15-19* (*Falkenberg*). In fact, GE would not have been indifferent about offering the savings in the form of a reduction to the purchase price of the equipment rather than through early termination of the rental agreement. GE would obviously prefer to offer the savings through termination of the rental agreement, which would have allowed the temporary CTs removed from Gadsby to be re-leased to other customers. On the other hand, a reduction in the purchase price of the peaking units would produce an immediate $7.5 million revenue reduction to GE. *Exh. No. 391 at 4:10-18* (*Anderberg*).

- It disregards the Company's evidence demonstrating the prudence of the Gadsby CTs. When the Gadsby Peaker presentation was made to the Board of Directors, it was noted that purchase of the GE CT was the better alternative irrespective of GE's offer to waive the $7.5 million lease obligation. *Id. at 3:13-17.* Moreover,

[27] During the Hunter outage and the Western power crisis, the Company leased mobile combustion turbine peaking units from GE and installed them at the Gadsby Plant to help mitigate production costs. Because additional capacity was required to serve retail load even after the return of Hunter to service, the Company offered to extend the lease of this equipment through September 2002 and signed a contract with GE to lease the mobile peakers for $9.5 million. During this time a variety of other peaking resources were being considered, including alternative technologies, sites, equipment suppliers, and purchases. Initially Pratt & Whitney units were selected because that supplier could meet the Company's installation schedule. However, in August 2001, GE offered an LM6000 unit that was significantly larger and more efficient to operate than the Pratt & Whitney units, and PacifiCorp was provided a turn-key offer at a cost that, on a $/kW basis, was equivalent to the Pratt & Whitney installation. In addition, GE offered to terminate the lease on the mobile peakers if the GE LM6000 was purchased.

although the turn-key offer was for $80.4 million, the final costs were closer to $70 million. *Id.*

- It is unsupported by accounting principle. The Company's rate base investment in the Gadsby CT reflects its actual costs, which is consistent with GAAP. *Id. at 4:2-3*. In contrast, there is no basis in accounting theory for deducting from this actual cost the savings that the Company may have realized in a separate transaction with the same vendor.

- The "theory" supporting it is flawed. Mr. Falkenberg's claim that an adjustment is warranted due solely to the claimed presence of a "conflict of interest" is illegitimate. The "conflict" described by Mr. Falkenberg is present in any number of situations in utility ratemaking. Before a disallowance is appropriate, however, some evidence of imprudence must be offered, and Mr. Falkenberg has failed to provide any evidence beyond his reference to a claimed "conflict of interest."

The Wyoming Commission recently rejected this same proposed adjustment from Mr. Falkenberg, concluding that "[t]he hypothetically conjoined transaction which amounts to a 'price concession' by General Electric was not demonstrated beyond the level of theory and surmise." *Exh. 447 ¶ 59b*. For the same reasons, Mr. Falkenberg's adjustment to the Gadsby CT rate base investment should be rejected, and the Company's original cost should continue to be used.

(ii) Mr. Falkenberg's Proposed Adjustment to the WAPA Wheeling Contract Should Be Rejected, as It Is Based on a Speculative, After-the-Fact Review of a 42-Year-Old Contract That was Reasonable at the Time It Was Executed.

103. ICNU witness Falkenberg proposes to impute revenue to a contract executed in 1962 under which PacifiCorp provides wheeling to WAPA customers. *Exh. No. 401C at 49:21 – 51:4*. Mr. Falkenberg provides no analysis or testimony in support of his adjustment, other than references to similar adjustments adopted by the Utah and Oregon commissions.[28] *TR. 566:9-13; Exh. No. 444*. His reliance on these orders is both improper and incomplete.

104. First, he mischaracterizes the Utah PSC decision upon which he relies. Although his testimony states that "the Utah PSC determined that the lack of price escalators in an 80-year

[28] Mr. Falkenberg offered no evidence regarding the prudence of the WAPA contract at the time it was entered, nor did he provide any evidence showing that the FERC transmission rate provides a reasonable basis for calculating an adjustment. (*TR. 321.*)

contract was imprudent," *Exh. No. 401C at 50:20-21*, in fact the Utah PSC ***expressly declined to reach that decision.*** The Utah PSC decision cited by Mr. Falkenberg states:

> *Without explicitly ruling on the Division's testimony that the Company behaved imprudently by entering into long-term contracts having no escalation provisions*, we conclude that the record contains no basis upon which to adopt the Company's rationale for abandoning the imputation policy, and we will not do so. *TR. 569:21 – 570:2* (*Falkenberg*) (*emphasis added*).

105. Second, the Utah PSC decision on which he relies was based upon testimony regarding reasonableness of the utility's conduct under the circumstances at the time the contract was entered,[29] a standard that Mr. Falkenberg agrees is "the typical prudent standard." *Id. at 569:7-12.* No such testimony or analysis was presented in this case, thereby failing to provide the Commission with an evidentiary basis for making the adjustment.[30]

106. Given the absence of an evidentiary foundation, the recent decision of the Wyoming Commission rejecting this adjustment may be instructive:

> The WAPA wheeling contract term began in 1962, and we will not now, 42 years on, start to remake it. The contract is too old for us to look back and make a reasonable analysis of the prudency of entering it, especially in view of the nature of the parties, the limited scope of the contract and the modest contribution to reducing the revenue requirement. We suspect that the company was driven by considerations other than simply maximizing its profits when it entered into this 80-year agreement with the WAPA in 1962, but that must remain speculation, as would any adjustment that sought to establish the contract as somehow imprudent at this late date. *Exh. 447 ¶ 72b.*

107. The adjustment to impute revenues for this 42-year-old contract should be rejected.

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[29] Specifically, the Division presented a witness who was an employee of the Company in 1962 when the contract was signed. *TR. 568:14-23.*

[30] In the Company's view, the WAPA wheeling contract provides benefits to Washington customers, and there is no basis for finding the contract to be imprudent. The WAPA wheeling contract was not intended to recover the fully loaded system costs decades into the future. It was intended to pay a reasonable share of the capital and operating costs for a specific line. Now that the capital investment in that line is largely depreciated, contract revenue amounts to a credit that reduces retail revenue requirement. *Exh. No. 391 at 5:10-22* (*Anderberg*).

F. The Commission Should Adopt the Remaining Provisions of the Settlement Agreement.

1. Prudence of Resource Acquisitions.

108. The revenue requirement recommended in the Settlement Agreement reflects the inclusion of the resources acquired by the Company since its last litigated general rate proceeding in Washington, Cause No. U-86-02. *Exh. 3 ¶ 10(c).* These resources include those described in the Joint Report in the Prudence Review of Generating Resources Acquired Since 1986, Exhibit No. 134 (the "Joint Report"), as well as West Valley and Gadsby. In the case of the resources described in the Joint Report that are located in the Company's Western Control Area (Hermiston and James River), this resolution is intended to be binding for purposes of this and future proceedings. The settling parties agree that these resources were prudently acquired for purposes of serving Washington customers, and are properly included in the Company's rate base for purposes of this case and subsequent proceedings. *Id.*

109. This is not the case with respect to the remaining resources, however. Due to Staff's use of a Control Area approach as the basis for cost allocations in its revenue requirement recommendation, Staff did not take a position for purposes of this Settlement Agreement with respect to the prudence for purposes of Washington rates of those resources acquired since 1986 located in the Company's Eastern Control Area (West Valley, Gadsby, Craig, Hayden, Foote Creek, and Cholla). Under paragraph 10(c) of the Settlement Agreement, the prudence of those resources will be examined in a subsequent proceeding if and when it is determined that the interjurisdictional cost allocation methodology requires their prudence to be evaluated for purposes of setting Washington rates.

110. Nonetheless, the Commission has some assurance regarding the prudence of the Eastern Control Area resources for purposes of setting rates in this proceeding. The Joint Report includes the results of the investigation regarding the prudence of four of these eastside resources: Craig, Hayden, Cholla, and Foote Creek. *Exh. No. 134.* The Joint Report concludes that these resources have been shown to be prudent on a systemwide basis. According to the Joint Report:

> Based on the information provided, Staff believes that the resources were acquired prudently when evaluated from a system-wide basis. Staff did not investigate whether the resources were acquired to satisfy the demand of Washington customers. These resources could be subjected to investigations in future rate proceedings that will determine whether these resources were acquired prudently to satisfy increased load growth or demand in Washington State, including consideration of the Company's commitments under merger agreements and orders, the impact of the "interjurisdictional" allocation used by the Company, and particular load-growth characteristics of the Company's Washington service territory. *Exh. 1 at 16:10-19* (*panel*).

111. The record thus demonstrates the prudence of these resources (*TR 339:3-7* (*Omohundro*)), with the remaining issue limited to whether their costs are properly allocable to Washington customers. *TR. 341:17 – 342:5* (*Braden*). Although Gadsby and West Valley have not yet undergone a thorough prudence review, the record contains evidence sufficient to make a *prima facie* showing that their acquisition was prudent, at least on a systemwide basis.[31] *Ex. 1 at 16:22-25.*

2. Regulatory Assets and Deferred Debits.

112. Paragraph 12 of the Settlement Agreement addresses these issues, which include FAS 87, Trail Mountain mine costs, and environmental remediation costs.

113. With respect to FAS 87 costs, the Company filed a Request for an Accounting Order Regarding Treatment of Pension Liability filed on November 17, 2003 (Docket No. UE-031878). Recognizing that it would soon file a general rate case, the Company requested a process by which a ruling on the petition be deferred until the completion of the Company's rate case. *Exh. 1 at 18:9-14* (*panel*). Under paragraph 12(a) of the Settlement Agreement, Staff agrees to expedited processing of this request. The settling parties further agree—and request

[31] *See Exh. No. 191 at 6:17 – 17:4, Exh. Nos. 192-199 (Tallman).*

confirmation by the Commission—that the Company's actuarially determined FAS 87 pension expense is a recoverable cost.

114. With respect to Trail Mountain Mine costs, the Company on October 13, 2003 filed a petition for an accounting order regarding unrecovered costs at its Trail Mountain Mine (Docket No. UE-031657). Paragraph 12(b) of the Settlement Agreement recommends that the Commission issue an accounting order authorizing the Company to accumulate the $46.3 million reflecting the Company's unrecovered investment in the Trail Mountain Mine and related mine closure costs and to record such investment in Account 182.3.[32] The settling parties request that the Commission approve deferral of these costs as of April 1, 2001. In addition, the Settlement Agreement requests Commission authorization of five years as a reasonable period over which to amortize the costs associated with the Trail Mountain Mine closure, with amortization commencing with the establishment of the deferral, April 1, 2001, and ending March 2006. *Id. at 18:15 – 19:4.*

115. With respect to costs associated with environmental remediation, the Company on October 13, 2003 filed a petition for an accounting order regarding treatment of environmental remediation costs (Docket No. UE-031658). Paragraph 12(c) of the Settlement Agreement recommends that the Commission issue an accounting order authorizing the Company to record and defer costs prudently incurred in connection with its environmental remediation program, on an ongoing basis. Costs eligible for such accounting treatment would be limited to only those amounts relating to work of outside vendors and contractors for investigation and feasibility studies, sampling, evaluation, monitoring, materials, remediation, and removal, disposal, and postremediation work, and do not include costs related to Company personnel or legal costs. *Id. at 19:12-16.* In addition, the Settlement Agreement requests a Commission

[32] This $46.3 million figure reflects the Company's partial ownership of the mine. *TR. 295:15-25 (Weston).*

finding that 10 years is a reasonable period over which to amortize these environmental remediation costs. *Id. at 19:16-19.*

116. With respect to other regulatory assets, Paragraph 12(d) of the Settlement Agreement provides that except as specifically set forth in the adjustments, all remaining regulatory assets and liabilities would be recognized in rates for purposes of the settlement. *Id. at 19:22-24.* As stated in Section III.D.3.e above, the Company has complied with the applicable regulatory requirements for the regulatory assets to which this treatment would apply.

3. Grid West Deferred Costs.

117. Both Staff witness Buckley, *Exh. No. 581 at 149:19 – 151:4*, and ICNU witness Schoenbeck, *Exh. No. 461 at 16:18 – 17:3*, challenged the Company's recovery of costs related to the development of an RTO. The Settlement Agreement disallows these costs for purposes of this proceeding. Paragraph 10(d) of the Settlement Agreement authorizes the Company to seek deferred accounting for these costs. *Exh. 1 at 9:20-22 (panel).*

4. Rate Spread/Rate Design.

118. Paragraph 11 of the Settlement Agreement provides that the settling parties agree to adopt the recommendations regarding rate spread and rate design set forth in the Joint Testimony of Mr. Lazar, Mr. Schoenbeck, and Ms. Steward, Exhibit No. 621. Exhibit No. 7 shows the rate impacts assuming the adoption of the revenue requirement increase recommended in the Settlement Agreement, and following the rate spread and rate design recommendations from Exhibit No. 621.

5. Removing Disincentives to Demand-Side Initiatives.

119. In the Company's direct testimony, it expressed an interest in implementing a decoupling mechanism designed to remove disincentives to investment in cost-effective demand-side resources. *Exh. No. 21 at 6:10-17 (Johansen).* The Company sought Commission endorsement of a simple system of periodic true-ups in electric rates, designed to correct for disparities between utilities' actual fixed cost recoveries and the revenue requirement approved by the Commission. *Id. at 7:1-3*. While a specific mechanism was not developed in this proceeding, the Settlement Agreement recommends that the Commission's order in this proceeding address the issue of whether it is in the public interest to investigate such a true-up mechanism, based on a review of NRDC's testimony and other information in the record. *Exh. 3 ¶ 13*. Upon such a finding, the Company will initiate discussions with Staff and interested parties (1) to review the effects of demand-side investments on the recovery of fixed costs and other potential disincentives to such investments by the Company and (2) to address the potential structure of a true-up mechanism that would make recovery of these costs independent of retail electricity sales. The Settlement Agreement further provides that on the basis of these discussions, the Company may propose a true-up mechanism for consideration by the Commission at the earliest practicable time. *Id.*

6. Procedural Issues.

120. Under the Settlement Agreement, if the Commission accepts the Settlement Agreement upon the condition that the revenue requirement increase is different in amount than recommended in this Settlement Agreement (the "Revised Rate Increase"), the Company would be permitted to implement as of the end of the current suspension period an increase in the amount of the Revised Rate Increase, subject to refund, pending issuance of a final order by the Commission. *Exh. 3 ¶ 14(d)*. Given the process contemplated by WAC 480-07-750(2)(a) in the event of rejection of a proposed condition, it may not be possible to complete this proceeding within the current suspension period. The Company agreed to extend the suspension period for such period as is reasonably necessary to accommodate the process contemplated by WAC 480-07-750(2)(a). *TR. 81:14-25 (Van Nostrand)*. If the suspension period is in fact extended, the settling parties submit that an appropriate interim measure would be to permit the Revised Rate Increase to be implemented, subject to refund, pending the final determination in the case. This temporary relief—which comes into play only if the suspension period is extended—is not "interim" relief as that term has been applied by the Commission. *TR. 348:14-16* (*Omohundro*).

G. Adopting the Settlement Agreement Would Achieve the Objectives for This Case Defined by the Commission in Its Deferred Power Cost Order.

121. The Commission in its Deferred Power Cost Order defined a number of objectives that would be served by allowing a general rate case filing before the end of the Rate Plan Period. The Company respectfully submits that adoption of the Settlement Agreement would largely fulfill these objectives. These objectives, and the manner in which they are satisfied, are as follows:

Objective[33]	**How Satisfied**
Proposed power cost baseline "has neither been tested in the crucible of a fully litigated case, nor accepted by the Commission on the basis of a stipulation and supporting evidence submitted by the parties." ¶ 27	Settlement Agreement specifies an annual net power cost baseline—including identification of the adjustments adopted in reaching that figure—and is supported with evidence offered by the settling parties. *See Section III.E.1 above.*
"[T]he need to provide PacifiCorp an opportunity to earn a reasonable rate of return over the next several years; that is, maintaining sufficient rates." ¶ 41	Settlement Agreement updates PacifiCorp's overall rate of return to reflect current capital cost requirements, and specifies an overall rate of return (8.39%) against which future results of operations can be measured. *See Section III.D.1 above.*
"[A]ppropriate basis for interjurisdictional allocation of power costs has not been satisfactorily resolved." ¶ 30 "The absence of an allocation methodology . . . is one reason . . . that a general rate case is desirable." ¶ 31	Settlement Agreement uses the Original Protocol as an interim measure for purposes of setting rates in this proceeding. The settling parties have agreed upon a process and schedule—with a report to the Commission on April 1, 2005—for determining a permanent cost allocation solution. *See Section III.C.4 above; TR. 329:2-6* (*Omohundro*).

[33] References are to paragraphs in the Deferred Power Cost Order.

"[T]hird principal goal is accountability. . . . [T]he Commission's ability to achieve a thorough and comprehensive understanding of PacifiCorp's financial circumstances, both overall and with respect to its Washington operations." ¶ 42 "[P]ermit adequate oversight by the Commission." ¶ 49 Determine whether the standard of fair, just reasonable, and sufficient rates "will be satisfied when considered in light of a current test year with properly restated, normalized, and pro formed results." ¶ 23 "Such an examination [thorough review on a full general rate case record] is long overdue . . . . ¶ 23	• This proceeding accomplishes a thorough review on a full general rate case record. *TR. 334:9-18* (*Omohundro*). • Examination occurred on the basis of a recent test year (12 months ended March 31, 2003, pro formed for known and measurable changes through March 31, 2004). • This proceeding included all pre-filed testimony (three rounds), extensive discovery on such testimony, and additional rounds of testimony addressing Settlement Agreement. • Record enables a thorough and comprehensive understanding of PacifiCorp's Washington operations.

IV. CONCLUSION

122. For the reasons set forth above, the Company urges the Commission to adopt the Settlement Agreement as the basis for resolving the contested issues in this proceeding, and to issue an order authorizing a revenue requirement increase of $15.5 million on or before the end of the suspension period in this proceeding.

DATED: October 8, 2004.

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Exhibit A

Adjustment	Amount (thousands)	Explanation
Net power costs	$1,932	*See* Section III.E.
Temperature normalization	615	Staff adjustment to the Company's temperature normalization calculation, *Exh. No. 611 at 3:8-13* (*Mariam*), less incremental power costs associated with the increased loads, *Exh. No. 204 at 6:4-6* (*Weston*). *Exh. No. 1 at 7:17-22* (*panel*).
Working capital	622	Agreed-upon figure after considering Staff, *Exh. No. 641 at 18:1 – 22:2* (*Schooley*), and Public Counsel's *Exh. No. 521 at 10:12 – 20:9* (*Dittmer*) proposed adjustments to working capital, and Company's rebuttal thereto, *Exh. No. 204 at 13:11 – 17:13* (*Weston*). *Exh. No. 1 at 8:1-5* (*panel*).
Incentive payout	697	Adopts one-half of the adjustment proposed by Staff, which would have disallowed 50% of the payout under the Company's incentive compensation program. *Exh. No. 591 at 10:15 – 15:7* (*Huang*); *Exh. No. 371 at 2:11 – 8:2* (*Wilson*). *Exh. No. 1 at 8:6-9* (*panel*).
International assignee costs	2	Agreed-upon figure after considering Staff's proposed adjustment (*Exh. No. 591 at 9:1 – 10:13 (Huang)*) and Company's rebuttal thereto (*Exh. No. 204 at 3:1-5 (Weston)*). *Exh. No. 1 at 8:10-14 (panel).*
IRS settlement	1,311	Agreed-upon figure after considering Staff's *Exh. No. 601 at 19:12 – 24:17* (*Kermode*), and Public Counsel's *Exh. No. 521 at 27:16 – 38:9* (*Dittmer*) proposed adjustments to IRS settlement payments, and Company's rebuttal thereto, *Exh. No. 283 at 1:13 – 10:6* (*Martin*). Figure represents approximately one-half of amount proposed by Staff. *Exh. No. 1 at 8:15-20* (*panel*).
Property insurance	630	Agreed-upon figure after considering Staff's proposed adjustment, *Exh. No. 641 at 11:1 – 12:7* (*Schooley*) and Company's rebuttal thereto, *Exh. No. 375 at 2:1 – 7:18* (*Fryer*). *Exh. No. 1 at 9:1-4* (*panel*).
Environmental costs	32	Agreed-upon amount that is calculated by reference to a proposed exclusion of legal and Company personnel costs. *Exh. No. 641 at 15:13 – 17:2* (*Schooley*); *Exh. No. 1 at 9:5-9* (*panel*).
Severance normalization	177	Accepts Staff's position to use a three-year average for purposes of this cost item. *Exh. No. 591 at 15:9-18* (*Huang*); *Exh. No. 1 at 9:10-13* (*panel*).

Property tax	(156)	Accepts Staff's proposed adjustment. *Exh. No. 601 at 15:4 – 17:7* (*Kermode*); *Exh. No. 1 at 9:14-16* (*panel*).
RTO costs	340	Accepts adjustments proposed by Staff's *Exh. No. 581 at 149:19 – 151:4* (*Buckley*), and ICNU's *Exh. No. 461 at 16:18 – 17:3* (*Schoenbeck*) to exclude costs related to the development of a Regional Transmission Organization ("RTO"). *Exh. No. 1 at 9:17-22.* Paragraph 10(d) of the Settlement Agreement authorizes the Company to seek deferred accounting for these costs. *Exh. No. 3.*
Cost of capital	3,500	*See* Section III.D.1.
Unspecified ICNU/Public Counsel adjustments	600	Agreed-upon figure to reflect that some of the remaining adjustments proposed by ICNU and Public Counsel may be perceived as having merit. *Exh. No. 1 at 11:1-8* (*panel*).
Interest expense true-up of adjustments	(144)	Reflects a true-up to capture the changes to rate base arising from the various revenue requirement adjustments. *Exh. No. 1 at 11:9-11* (*panel*).
TOTAL	$10,158	

Source: *Exh. No. 3, Att. A.*

Exhibit B

EXHIBIT B

Adjustment	Amount (millions)	Explanation
Remove Swift	$8.82	Reflects the removal of the near-term impact on the loss of reserves at Swift 1 as a result of the canal embankment failure on Cowlitz's Swift 2 project. *Exh. No. 1 at 13.*
Aquila hydro hedge	1.75	Removes costs associated with these hedges; Company retains any payments received under the hedges. *Exh. No. 1 at 13.*
J. Aron temperature hedge	2.10	
Morgan Stanley temperature hedge	1.80	
Hydro normalization	4.60	Excludes certain years from the water year record considered in normalizing hydro costs, specifically those years when generation falls outside one standard deviation from the mean. *Exh. No. 1 at 13.*
Mid-Columbia market caps	1.59	Imputes additional energy sales from the Jim Bridger coal plant as a means for correcting the market caps imposed by the Company for modeling purposes on the Mid-Columbia market during light load hours. *Exh. No. 1 at 13-14.*
CT dispatch	.23	Adjusts logic of the dispatch of the Company's combustion turbines ("CT's") for modeling purposes. *Exh. No. 1 at 14.*

Source: *Exh. No. 3, Att. B.*

Adjustments proposed by ICNU witness Falkenberg that were incorporated in the Company's rebuttal case.

Adjustment	Amount ($)
West Valley heat rates	(1,574,536)
Wyodak capacity	(1,626,984)
Fort James cogeneration	(401,733)
Market cap input error	(2,931,927)
Quick start benefits	(1,000,000)
TOTAL	(7,535,180)

Source: *Exh. No. 3, Att. B.*

CERTIFICATE OF SERVICE

I hereby certify that I served a copy of the foregoing document upon the parties of record in this proceeding by first-class mail, addressed to said parties/attorneys' addresses as shown below:

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