[Service Date February 18, 2005]

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND	)	
TRANSPORTATION COMMISSION,	)	
	)	DOCKET NOS. UG-040640 and UE-
Complainant,	)	040641 (consolidated)
v.	)	
	)	
PUGET SOUND ENERGY, INC.,	)	
	)	
Respondent.	)	
. . . .	)	
In the Matter of the Petition of	)	DOCKET NO. UE-031471
PUGET SOUND ENERGY, INC.,	)	(consolidated)
	)	
For an Order Regarding the	)	
Accounting Treatment For Certain	)	
Costs of the Company's Power Cost	)	
Only Rate Filing	)	
. . . .	)	
In the Matter of the Petition of	)	DOCKET NO. UE-032043
PUGET SOUND ENERGY, INC.,	)	(consolidated)
	)	
For an Accounting Order Authorizing	)	ORDER NO. 06: FINAL ORDER
Deferral and Recovery of Investment	)	REJECTING TARIFF SHEETS;
and Costs Related to the White River	)	AUTHORIZING AND REQUIRING
Hydroelectric Project	)	COMPLIANCE FILING;
. . . .	)	REQUIRING SUBSEQUENT FILING

Synopsis*: The Commission rejects tariff sheets originally filed in this docket by Puget Sound Energy, Inc. (PSE) seeking to increase electric rates by $81,600,777 and natural gas rates by $47,242,425. The Commission determines that PSE is authorized to file revised tariff sheets to increase electric rates by $56,592,001 (minus allocation to wholesale) and natural gas rates by $26,297,231.*

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SUMMARY

1 **PROCEEDINGS:** The Commission resolves four consolidated dockets affecting Puget Sound Energy, Inc.'s ("PSE" or the "Company"), rates, terms, and conditions of gas and electric service provided to customers in Washington. Docket Nos. UG-040640 and UE-040641 are general rate proceedings concerning, respectively, the Company's gas and electric rates. PSE filed proposed tariff revisions on April 5, 2004. The Commission suspended the proposed revisions by entry of Order No. 01 on April 28, 2004, consolidated the two dockets, and set the matters for hearing.

2 PSE filed a petition in Docket No. UE-031471 on September 12, 2003, for authority to defer costs associated with outside services related to the Company's PCORC (Power Cost Only Rate Case) filing during 2003. The petition asked that these costs be reviewed and the amortization set in the Company's next general rate proceeding. The Commission consolidated Docket No. UE-031471 with these rate proceedings, as requested.

3 PSE filed a petition in Docket No. UE-032043 on December 10, 2003, for an Accounting Order Authorizing Deferral and Recovery of Investment and Costs Related to the White River Hydroelectric Project. The Commission consolidated Docket No. UE-031471 for hearing with the other pending matters.[1]

4 The Commission conducted prehearing and hearing proceedings before Chairwoman Marilyn Showalter, Commissioner Richard Hemstad, Commissioner Patrick J. Oshie, and Administrative Law Judge Dennis J. Moss. The Parties filed Initial Briefs on January 18, 2005, and Reply Briefs on January 27, 2005. The Commission, by entry of this Final Order, resolves all issues pending in the four dockets and orders appropriate relief.

[1] Because the general rate filing proceedings are considered the lead dockets, subsequent orders will be captioned in the fashion of this Order, and numbered based on the sequence established in the lead dockets.

5 **PARTY REPRESENTATIVES:** Kirstin S. Dodge and Jason Kuzma, Perkins Coie, Bellevue, Washington, represent PSE. Michael L. Kurtz and Kurt J. Boehm, Boehm, Kurtz & Lowry, Cincinnati, Ohio, represent the Kroger Co., on behalf of its Fred Meyer Stores and Quality Food Centers divisions (collectively "Kroger"). Elaine L. Spencer, Graham & Dunn PC, Seattle, Washington, represents Seattle Steam Company ("Seattle Steam"). S. Bradley Van Cleve and Matthew W. Perkins, Davison Van Cleve, Portland, Oregon, represent the Industrial Customers of Northwest Utilities ("ICNU"). Norman Furuta, Department of the Navy, represents the Federal Executive Agencies ("FEA"). John Cameron, Davis Wright Tremaine, LLP, Portland, Oregon, represents AT&T Wireless Services, Inc. ("AWS") and Cost Management Services, Inc. ("CMS"). Edward A. Finklea and Chad M. Stokes, Cable Huston Benedict Haagensen & Lloyd LLP, Portland, Oregon, represent Northwest Industrial Gas Users ("NWIGU"). Danielle Dixon, Senior Policy Associate, NW Energy Coalition ("NWEC"), represents the NWEC. John O'Rourke, Director, Citizens' Utility Alliance ("CUA"), represents the CUA. Ronald L. Roseman, Attorney, Seattle, Washington, represents Energy Project and A World Institute for a Sustainable Humanity ("A W.I.S.H."). Simon ffitch, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington Office of Attorney General ("Public Counsel"). Robert D. Cedarbaum, Senior Assistant Attorney General, Olympia, Washington, represents the Commission's regulatory staff ("Commission Staff or Staff").[2]

6 **COMMISSION DECISIONS**: The Commission determines that the rates proposed by tariff revisions filed by Puget Sound Energy, Inc., on April 5, 2004, and suspended by prior Commission order, are not just, fair, or reasonable and should be rejected. The Commission also determines that the Company's existing rates are insufficient to yield reasonable compensation for the services rendered. The Commission determines that PSE's natural gas rates should be

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[2] In formal proceedings, such as this case, the Commission's regulatory staff functions as an independent party with the same rights, privileges, and responsibilities as any other party to the proceeding. There is an "*ex parte* wall" separating the Commissioners, the presiding ALJ, and the Commissioners' policy and accounting advisors from all parties, including Staff. *RCW 34.05.455*.

increased in accordance with the terms of this Order to allow for recovery of a revenue deficiency of $26,297,231. The Commission determines that PSE's electric rates should be increased in accordance with the terms of this Order to allow for recovery of a revenue deficiency of $56,592,001[3].

MEMORANDUM

I. Background and Procedural History

7 On April 5, 2004, PSE filed with the Commission revisions to its currently effective Tariff WN U-60, Tariff G, Electric Service, Advice No. 2004-09, and revisions to its currently effective Tariff WN U-2, Gas Service, Advice No. 2004-10. The proposed tariff revisions bore an effective date of May 6, 2004. PSE proposed a general rate increase of 6.5 percent for the electric tariffs and 6.29 percent for the gas tariffs. The Commission suspended the proposed tariff revisions by entry of Order No. 01 on April 28, 2004, consolidated the two dockets, and set the matters for hearing.

8 On September 12, 2003, PSE filed in Docket No. UE-031471, a petition requesting authority to defer to FERC Account 182.3, Other Regulatory Assets, the costs of outside services related to its first PCORC filing before the Commission. The Company specifically asked that the deferred costs be included in working capital in future rate proceedings. The Petition also effectively asks that these costs be reviewed and the amortization set in this general rate proceeding.

9 On December 10, 2003, PSE filed in Docket No. UE-032043, a petition for an Accounting Order Authorizing Deferral and Recovery of Investment and Costs Related to the White River Hydroelectric Project. As in the case of Docket No. UE-031471, it is appropriate for the issues in Docket No. UE-032043 to be considered in the context of a general rate case in which the potential results of granting or denying the petitions may be assessed.

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[3] The revenue deficiency must be adjusted to account for allocation to wholesale. *See*, Table Six.

10 On April 28, 2004, the Commission entered Order No. 02 in Docket Nos. UG-040640 and UE-040641, Order No. 01 in Docket No. UE-031471, and Order No. 01 in Docket No. UE-032043, consolidating the four dockets.

11 The Commission conducted a prehearing conference on May 17, 2004, before Administrative Law Judge Dennis J. Moss. On May 19, 2004, the Commission entered Order No. 03, granting various pending petitions to intervene, authorizing formal discovery, and establishing a procedural schedule.

12 The parties prefiled extensive testimony and numerous exhibits sponsored by 27 witnesses, including 13 for PSE, 6 for intervenors, 2 for Public Counsel, and 6 for Staff. On December 6, 2004, Staff filed a proposed Rate Spread and Rate Design Settlement that was supported by all parties that had prefiled testimony concerning those subjects. The proposed settlement was not opposed by any party. The Settlement filing was accompanied by joint testimony and exhibits sponsored by a panel of witnesses who earlier had filed testimony on rate spread and rate design issues. The Commission conducted evidentiary hearings from December 13 – 16, 2004, and held its second public comment hearing, in Olympia, during the evening hours on December 16, 2004.[4] Altogether the record includes more than 350 exhibits entered during four days of evidentiary proceedings. The transcript of these proceedings is over 1,000 pages in length.

13 The parties filed Initial Briefs on January 18, 2005, and Reply Briefs on January 27, 2005. The Commission here enters its Final Order resolving the disputed issues, approving certain uncontested adjustments, and granting appropriate relief considering the full record of proceedings and the parties' arguments based on that record.

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[4] The Commission conducted its first public comment hearing, in Bellevue, on November 10, 2004.

II. Discussion and Decisions

A. Capital Structure and Cost of Capital

14 "By far and away, the issue that separates the parties is the cost of capital."[5] PSE, Staff, and Public Counsel each present comprehensive proposals for capital structure and cost of capital. NWIGU briefs the issue, urging us to use "common sense" to evaluate the analytical evidence and theories presented by those claiming expertise in the complex field of financial consulting.[6]

15 The Commission established PSE's current overall rate of return by approving a partial settlement in Docket Nos. UE-011570 and UG-011571 during 2002.[7] The Commission accepted the settling parties' recommendation of an overall return of 8.76% based, in part, on a hypothetical equity share of 40% and return on common equity of 11%. PSE's actual capital structure at the time included 31.7% equity. By December 31, 2003, PSE's equity ratio had increased to 39.2%.

16 PSE acknowledges that its financial condition since the settlement of its general rate case in 2002 has improved, but the Company argues that it remains short of where it needs to be. PSE argues that it must further improve its financial health to secure a stably priced, long-term supply of energy resources for its customers, and to enhance its risk management capabilities to limit customers' exposure to volatile wholesale energy markets. The Company states that it needs continued regulatory support to achieve its critical goals.[8]

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[5] Staff Initial Brief at 1.

[6] NWIGU Initial Brief at 7 (citing *Pacific Power & Light*, 68 P.U.R. 4th 396, 85 WL 514900, 16 ("The commission approves the use of common sense in analysis and the use of common sense as a test or validation of technical theory.")); see *State v. Dixon*, 78 Wn.2d 796, 479 P.2d 931.

[7] *WUTC v. PSE*, Docket Nos. UE-011570, UG-011571, Twelfth Supplemental Order (June 2002) and Thirteenth Supplemental Order (August 2002).

[8] PSE Initial Brief at 1 (citing Exh. No. 51 at 3:8 – 12:8 (Reynolds); Exh. No. 53 at 2:3 – 6:13 (Reynolds); Exh. No. 151 at 3:4 – 9:14 (Valdman); Exh. No. 154 at 2:1 – 5:9 (Valdman); Exh. No. 171C at 20:14 – 24:9 (Gaines)).

17 PSE states that over the next several years it will need to make significant investments in new energy resources and new electric and gas delivery infrastructure to serve its growing customer base, and to upgrade aging facilities. No Party disputes this statement. These investments will require PSE to access large sums of capital over the next several years.[9] One of PSE's goals as it anticipates these needs is to improve the Company's corporate credit rating from the current BBB- level to BBB+.[10] PSE argues that such improvement in its corporate rating "would allow the Company to access capital markets on more favorable terms, expand the Company's ability to engage in hedging activities in wholesale gas and power markets, and enhance the Company's negotiating strength in its resource acquisition efforts."[11]

18 PSE argues that our approval of its proposed overall rate of return of 9.12%, reflecting a 45% equity share and return on equity of 11.75%, would help the Company achieve its financial goals.

19 Staff argues that PSE's financial condition is already sound and that its requested return significantly overstates what is required or justified under current circumstances. Staff contends that PSE can maintain, and even improve its financial strength without being granted approval for its proposed capital structure and return. Staff points out that the Company continues to maintain a corporate bond rating in the triple B range[12] with an equity ratio that has only recently achieved the 39-40% level.[13] Staff argues that the evidence shows PSE has enjoyed favorable access to financial markets over the last three years and is in a stronger position now than during the Western power crisis.[14] Staff points to

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[9] *See* Exh. No. 61C at 3:10 – 15:10 (Markell); Exh. No. 131C at 10:15 – 25:12 (McLain).
[10] Both PSE and its parent, Puget Energy, Inc. are currently rated by Standard & Poor's as BBB- at the corporate level. PSE's senior secured debt is rated at BBB.
[11] PSE Initial Brief at 2 (citing Exh. No. 51 at 8:3 – 12:8 (Reynolds); Exh. No. 61C at 10:4 – 15:10 (Markell); Exh. No. 71at 16:18 – 24:21 (Ryan); Exh. No. 82C at 3:1 – 9:4 (Ryan); Exh. No. 84C at 2:5 – 15:9 (Ryan)).
[12] Exh. No. 54 at 3; TR. 144:11-21 (Reynolds); TR. 180:20-23 and 184:17-24 (Valdman).
[13] Staff Brief at 3 (citing TR. 181:4-7 and 187:1-7 (Valdman)).
[14] *Id. (*citing Exh. No. 161).

Puget Energy's 2003 Annual Report, which states that "under the most restrictive tests," PSE is able to issue almost $1 billion of additional first mortgage bonds, $454 million of preferred stock, and $261 million of unsecured long-term debt.[15]

20 With respect to infrastructure investment, Staff argues that from 2001-2003, the Company fully covered all construction and capital expenditures with internally generated funds and that it can continue to do so today.[16] Staff points out that PSE's President and CEO, Mr. Reynolds, testified that it is unnecessary for the Company to reach a 45% equity ratio in order to fund its capital projects.[17]

21 Staff argues that PSE's risk management activities also show improvement, citing evidence that shows the Company has recently increased the number of physical and financial counterparties with which it does business.[18] Staff argues that Ms. Ryan's testimony demonstrates that PSE's credit today is adequate to hedge power supply in futures markets for significant periods.[19]

22 Focusing on equity share, Staff argues that setting rates on the basis of PSE's proposed 45% equity ratio, rather than the Company's actual expected equity ratio over the course of the rate year, would require ratepayers to pay for "phantom equity costs" amounting to millions of dollars per year.[20] Staff recommends that we approve an overall rate of return of 7.80%, an equity share of 41.84%, and a return on equity of 9.00%.

23 Public Counsel argues that the Commission, having supported PSE by authorizing a hypothetical 40 % equity ratio in 2002 when the Company's actual capitalization included less than 32% equity, and by providing other significant

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[15] Exh. No. 54 at 3; TR. 145: -8 (Reynolds).
[16] Staff Brief at 3-4 (citing Exh. No. 54 at 4 (Compare "Net cash provided by operating activities" and "Construction and capital expenditures—excluding equity AFUDC"); TR. 146:3-7 (Reynolds); Exh. No. 206C at 52:6-7 (Cicchetti)).
[17] TR. 161:18-23 (Reynolds).
[18] Staff Initial Brief at 4 (citing Exh. No. 82C at 6:14-16 (Ryan); Exh. No. 74C; Exh. No. 89C).
[19] *Id.* (citing TR. 909:13-18 and 948:13 to 949:12 (Ryan).
[20] *Id.* at 7.

regulatory support for the Company, should not again approve a capital structure that will allow PSE to collect from customers return on equity that the Company, in fact, does not have. Public Counsel estimates the impact of a 5% increase in PSE's common equity ratio, from the current 40% to 45%, will be approximately $15 million additional in electric rates alone.[21]

24 Referring to the settlement in PSE's 2002 general rate proceeding, which it supported, Public Counsel states that "PSE's Washington ratepayers agreed to provide a return on common equity capital the Company did not have, in the context of an incentive mechanism."[22] Public Counsel argues this was accepted in the prior case as an extraordinary measure to help the Company reach an acceptable capital structure, which has been achieved. Public Counsel states that "the agreed target has been reached and Washington ratepayers have done their part in restoring the Company to a normal, industry-average capital structure."[23]

25 Public Counsel urges an overall rate of return of 8.01%, a 40% equity share, and a return on equity of 9.75%.[24] Public Counsel argues that its recommended cost of capital results are adequate to provide the Company with a return that will meet investor requirements, maintain the Company's credit, and maintain its ability to attract capital, thereby protecting the public interest.[25]

26 Tables showing the full capital structures and cost rates in PSE's current rates, and as proposed by all three parties, are attached to this Order as "Appendix A."

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[21] Public Counsel Initial Brief at 9, 22 (citing Exh. No. 351 at 23 (Hill); Exh. No. 357at 4). We note that Staff estimates the amount at $34.7 million on the full Company rate base (*i.e.*, gas and electric). Staff Initial Brief at 7.
[22] Public Counsel Initial Brief at 23.
[23] *Id.*
[24] Public Counsel Brief Appendix A
[25] Public Counsel Initial Brief at 8 – 9.

1. Common Equity

a. Equity Ratio

27 Establishing a capital structure for ratemaking purposes requires the Commission to strike an appropriate balance between debt and equity on the bases of economy and safety.[26] The economy of lower cost debt, on which the Company has a legal obligation to pay interest, must be balanced against the safety of higher cost common equity on which the Company has no legal obligation to pay a return at any particular time. The Commission has used actual, pro forma, or imputed capital structures to strike the right balance and determine overall rate of return on a case-by-case basis.[27]

28 Public Counsel argues that we should use PSE's actual end-of-test-year equity ratio of approximately 40%. Public Counsel states that the Company's requested capital structure contains far more common equity and less debt capital than actually employed by the Company, on average, over the past five quarters.[28]

29 Public Counsel argues that the Company's requested capital structure is more equity-rich than that of its riskier parent company, Puget Energy. Public Counsel cites to Mr. Hill's testimony that setting rates for PSE using a capital structure similar to its riskier parent would require the ratepayers to provide an inappropriate financial cross-subsidy to the parent's unregulated operations.[29] There is no evidence, however, that any such cross-subsidy exists or will materialize if we set an equity ratio higher than 40%.

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[26] *WUTC v. Puget Sound Power & Light Co.,* Cause Nos. UE-920433, *et al.*, Eleventh Supplemental Order at 25-26 (Sept. 1993); PSE Initial Brief at 10, ¶ 26; Staff Initial brief at 22, ¶ 74.
[27] WUTC *v. Pacific Power & Light Co.,* Cause No. U-83-33, Second Supplemental Order at 8 (Feb. 1984); see also *WUTC v. Puget Sound Power & Light Co.,* Cause Nos. UE-920433, *et al.*, Eleventh Supplemental Order at 25-26 (Sept. 1993).
[28] Public Counsel Initial Brief at 22 (citing Exh. No. 351 at 18).
[29] *Id.* (citing Exh. No. 351 at 19-20).

30 Public Counsel also cites to Mr. Hill's testimony that the Company's requested capital structure contains substantially more common equity and less debt capital than exists, on average, for similar-risk companies in the electric utility industry.[30] Mr. Hill's testimony, however, also shows that the average ratios Mr. Hill discusses (*i.e.*, averages ranging from 36% to 43%) are derived from data including equity ratios for individual companies that range from 5% to 64%.[31] This wide range implies that the individual circumstances of regulated utilities must be taken into account when determining the equity ratio that is appropriate for a given company at a particular point in time. The averages to which Mr. Hill refers simply are not particularly useful measures to guide our decision.

31 Finally, as previously discussed, Public Counsel argues that the Company's requested capital structure would be economically inefficient, requiring Washington electric ratepayers to provide approximately $15 million annually of capital costs in excess of those necessary for a firm in its risk class.

32 The trend in PSE's actual equity ratio has been upward over the past two years. The Company achieved its equity ratio goal of 40% ahead of schedule relative to what was expected under the settlement terms adopted in 2002. It appears PSE will continue to grow its equity share into the rate year. It is appropriate given these facts, and PSE's particular circumstances, to afford more weight to forward considerations than to historic conditions as we determine the appropriate equity ratio to be embedded in prospective rates. We do not think it would be best in this instance to fix PSE's equity ratio at the current level or based on prevailing levels in the recent past. Rather, we find we should establish the Company's equity ratio in this case on a forward looking basis.

33 At the far forward end of the spectrum, PSE proposes that we approve an equity ratio of 45%. This is the goal PSE hopes to achieve by the end of the rate period through the growth of retained earnings in excess of dividends and by issuing

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[30] *Id.* (citing Exh. No. 351 at 20, 21; Exh. No. 357 at 3).
[31] Exh. No. 357 at 3.

new shares of common stock.[32] PSE argues that authorizing 45% equity in its capital structure today would be appropriate given the Company's anticipated generation acquisition and infrastructure investment activities, its need for a higher credit rating to support wholesale market hedging transactions, and its anticipated actual capital structure.[33]

34 As previously discussed, the Commission's decisions during 2002 to authorize PSE to earn a return on a hypothetical capital structure including 40% equity, and to approve two regulatory mechanisms designed to materially reduce the Company's risk (*i.e.*, the PCA and PCORC),[34] already have provided significant support to PSE's infrastructure investment activities, including the Fredrickson generation acquisition and other planned generation, and improved market risk management capability.[35] Though PSE may achieve its goal of an actual 45% equity in its capital structure, the timing of that achievement is uncertain, and, as advocated, is not expected before the end of the rate year.

35 Turning to PSE's goal of advancing its corporate credit rating by two steps, from BBB- to BBB+, we observe that ratings agencies consider a host of factors in deciding whether to upgrade a company, as Staff and others argue.[36] We have no reason to believe that allowing a 45% equity ratio in rates will be determinative as PSE works toward an improved corporate credit rating, particularly when the Company has not actually achieved that level.

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[32] Exh. No. 171C at 24:5-9.
[33] PSE Initial Brief at 11.
[34] The PCA mechanism establishes a baseline around which variable power costs are accounted for on an annual basis. Sharing bands balance market risks equally between shareholders and ratepayers. The PCORC is a form of proceeding that allows PSE to periodically adjust its power costs to account for changes such as the addition of generation assets. PCORC proceedings reduce or eliminate regulatory lag.
[35] We note in this connection the recent improvement in Standard & Poor's business risk rating for PSE from 5 to 4. TR. 478:1-11 (Gaines).
[36] Staff Initial Brief at 6 (citing Exh. Nos. 198, 199, and 200; TR. 193:1-9 (Valdman)).

36 Finally, we are mindful of Mr. Reynolds's testimony that: "We are going to be back in front of this Commission on a very regular basis year in and year out for the next—for the long term foreseeable future. There is every opportunity to continue to revisit this issue over time."[37] If the Company's actual equity continues to grow as PSE anticipates, the Commission will have the opportunity to consider that fact as it examines proposed rates in future proceedings.

37 Staking out the middle ground, Staff's witness, Dr. Wilson, testified that while PSE's proposal is not patently unreasonable, it is more reasonable to use "actual" pro forma debt and equity for the rate year.[38] Dr. Wilson takes the average of the Company's projected end of month capital structure for the twelve-month period February 2005 through January 31, 2006. The result is a projected average common equity ratio of 41.84%.[39]

38 PSE argues that Staff's equity ratio understates the rate year average equity because Dr. Wilson's analysis excluded the final month of the rate year, February 2006, and included January 2005, which preceded the rate year.[40] Mr. Gaines testified that by ending his calculations before the end of the rate year, Dr. Wilson excludes the impact of a common stock issuance included in the Company's financial plan for February 2006.[41] This equity issuance, when combined with retained earnings, is a significant factor in terms of moving PSE into the 45% range, according to Mr. Gaines.[42]

39 PSE also criticizes Dr. Wilson's decision to include in his analysis negative retained earnings of the Company's unregulated activities.[43] As Mr. Gaines testifies, negative retained earnings represent negative equity in this context,

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[37] TR. 163:1-5 (Reynolds).
[38] Exh. No. 481 at 30:8-9 (Wilson).
[39] Id. at 35:14.
[40] PSE Initial Brief at 12-13.
[41] Exh. No. 179C at 31:15-18 (Gaines).
[42] *Id.* at 32: 2-3.
[43] PSE Initial Brief at 13.

thus reducing Dr. Wilson's result by .26%, from 42.10% to the 41.84% Staff advocates.[44]

Commission Decision:

40 The evidence shows that PSE's financial health has improved and can reasonably be expected to continue to improve without the need for a hypothetical capital structure. Our goal in this proceeding should be to set the Company's equity ratio at the level that the evidence shows is most likely to prevail, on average, over the course of the rate year. We find that Staff's approach, with two modifications, brings us to the right balance between safety and economy as we determine PSE's capital structure for purposes of setting prospective rates on the basis of the rate year ending February 28, 2006. We modify Staff's approach, as supported by Dr. Wilson's analysis, by applying that approach to the actual 12 months of the rate year, and by excluding the negative equity of PSE's unregulated subsidiaries so as to isolate and focus on the regulated utility operations. We determine that PSE's capital structure should include an equity ratio of 43.00%.[45]

b. Cost of Equity

41 The parties are far apart on the cost of equity component that they contend should be embedded in rates. The record includes cost of capital evidence offered in support of a range of values from 8% to 12.9%, with parties advocating results in the range of 9.00% to 11.75%. Coupled with the various capital structures advocated, this produces overall return results ranging from Staff at 7.80%, Public Counsel at 8.01%, and PSE at 9.12%.[46]

42 Mr. Gaines, testifying for PSE, recommends an equity cost of 11.75%. Dr. Cicchetti testified for PSE in support of this recommendation, asserting that the

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[44] *Id.* at 33: 18-20.
[45] Exh. No. 178C at 2.
[46] See Appendix A.

Company requires a 12.2% return on equity at a minimum.[47] Dr. Cicchetti relied analytically on the discounted cash flow (DCF) approach in reaching his return on equity results. The DCF model is based on shareholder values and expectations. The model attempts to measure what level of equity return investors will demand in the market for a particular company, thus measuring that company's cost of money in the equity market.

43 DCF analysis requires the measurement of dividend yield and expected future growth in dividends.[48] Added together, these produce the cost of equity capital. The yield component of the DCF model is not controversial in this proceeding. All three witnesses used an average dividend yield of 4.4% in their analyses.[49]

44 Because it is the consensus of investor expectations that establishes the price of common equity, and investors' expectations are concerned with future income streams, the dividend growth component is critically important in DCF analysis. It must be set so as to reflect what investors actually, and reasonably, expect. Unlike dividend yield, where values are routinely published by Standard & Poor's and other respected financial analysts, there is no published consensus value for investors' expectations of dividend growth. Indeed, the dividend growth factor tends to be the chief source of contention among cost of capital expert witnesses generally, and that is the case here.

45 Dr. Cicchetti assumed in his DCF analysis that investors' dividend growth expectations can be inferred by comparing the closing price of a company's common stock in each month during a defined period, with the closing price in the corresponding month one year earlier.[50]

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[47] Exh. No. 201 at 36:2-6 (Cicchetti).
[48] PSE Initial Brief at 19; Staff Initial Brief at 14.
[49] Exh. No. 201 34:Table 5 (Cicchetti); Exh. No. 484 1:4 (Wilson); Exh. No. 351 52:Table 2 (Hill).
[50] Exh. No. 201 at 34 (Cicchetti) and Exh. No. 204.

46 Public Counsel argues that Dr. Cicchetti's use of stock price growth is "unorthodox and causes his DCF results to be extremely volatile." This volatility is apparent when we consider Dr. Cicchetti's DCF results for PSE as portrayed in Table 5 of his direct testimony.[51] He concludes, on the basis of an average over 13 months, that the overall DCF indication for PSE is a 12.2 % return on equity. Yet, as Public Counsel points out, Dr. Cicchetti's table shows a DCF for Puget Energy of 5% in August 2003 and 21.9% in January 2004, a dramatic variance of nearly 1700 basis points in PSE's cost of equity capital within a six month period. Public Counsel argues on the basis of Mr. Hill's analyses, that by simply updating Dr. Cicchetti's analysis by four months,[52] the average DCF result becomes 8.6%, a 360 basis point, or 30% reduction from Dr. Cicchetti's 12.2%.[53]

47 Dr. Cicchetti, on rebuttal, criticizes Mr. Hill's update on the basis that the additional months included in his analysis cover periods when Puget's stock price fell.[54] Public Counsel argues that this illustrates precisely why Dr. Cicchetti's use of stock price changes to set the growth rate in a DCF analysis is inappropriate; results depend entirely on what period the analyst selects for making his determination, and may vary significantly with even slight adjustments to the period under consideration.

48 Public Counsel refers to Dr. Cicchetti's DCF analysis of "comparable utilities," as portrayed in Table 6 of his testimony, as a further demonstration that his approach to DCF produces results that "are simply not credible".[55] Relying again on stock price changes as the basis for the growth rate variable in his model, Dr. Cicchetti shows resulting DCF-determined equity costs for comparable utilities that range from a high positive return of 50.6% for Great Plains Energy to a low

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[51] Exh. No. 201 at 34.
[52] Dr. Cicchetti used the period March 03-March 04. Mr. Hill applied Dr. Cicchetti's method to the period July 03-July 04.
[53] Exh. No. 351 at 52:Table 2 (Hill).
[54] Exh. No. 206C at 72:15.; 73:10 (Cicchetti); Exh. No. 255 (Cicchetti).
[55] Public Counsel Initial Brief at 33.

negative "return" of (22.8%) for Sierra Pacific Resources.[56] Significantly, while Dr. Cicchetti selects comparables based on criteria he asserts ensure similarity to PSE and each other, his model produces a positive 35.79% return on equity for Avista and an 11.99% return on equity for IDACORP. These two companies not only meet all of Dr. Cicchetti's criteria for similarity, they are likely to be even more similar to each other than certain other companies because both do a significant part of their business in the same state, Idaho.

49 Dr. Wilson, testified for Staff along the same lines as Mr. Hill for Public Counsel. Dr. Wilson described Dr. Cicchetti's approach as an unrealistically simplistic method for estimating investor dividend growth expectations, which are the result of far broader considerations than the percentage change in a company's stock price over the past year.[57] Staff summarizes Dr. Cicchetti's analysis, pointing out that of the eleven comparable companies Dr. Cicchetti uses, his DCF analysis produced returns on equity in excess of 25% for five companies, negative results for three companies, and estimates of 19% to 20% for the remaining three companies.[58] Staff argues that none of these results is a reasonable estimate of any company's cost of capital. Yet, as Staff observes, Dr. Cicchetti uses the average of these values as an indication of PSE's return on equity.[59] Public Counsel and Staff both argue, as Public Counsel puts it, that "these results, on their face, are simply not credible."[60]

50 Public Counsel continues:

> Statistical analysis casts even more doubt on Dr. Cicchetti's numbers. For example, a typical two standard deviation analysis around his average DCF for combination utilities (15.5%) results in the conclusion that the Commission can be 95% confident that

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[56] Exh. No. 201 at 35 (Cicchetti).
[57] Exh. No. 481 at 11: 4-7 (Wilson).
[58] Exh. No. 481 at 13:1-3 (Wilson).
[59] Exh. No. 201 at 35 (Cicchetti); Exh. No. 481 at 13:3-7 (Wilson).
[60] Public Counsel Initial Brief at 33; Staff Initial Brief at 16.

> Puget's ROE lies somewhere between -26% and + 51%.[61] This conclusion could have been reached with no DCF analysis at all. It is an understatement to say that analytical volatility of this magnitude is not useful to this Commission in setting the allowed return for the Company in this proceeding. It is essentially meaningless.[62]

51 We find that the growth assumption Dr. Cicchetti makes,[63] and the results he achieves relying on his assumption, simply do not pass the test of common sense. As Dr. Cicchetti observes: "There is a widely accepted tenet in quantitative analysis that the final calculation can be no more reliable than the weakest link in the mathematical chain of logic."[64] Measured against that test, Staff and Public Counsel's criticisms of Dr. Cicchetti's analyses and determinations of equity return are extremely well taken. His results, as these parties argue, are "essentially meaningless" and are "not credible."[65] We find that we can give little or no weight to Dr. Cicchetti's DCF analyses or results.

52 Dr. Cicchetti also performed a Capital Asset Pricing Model (CAPM) analysis. There are three elements in the CAPM: Beta, the risk-free rate, and the equity risk premium.[66] Beta is a measure of the risk in a single stock as compared to risk in the broader market.[67] Value Line and other trusted financial publications calculate Beta for many companies, including Puget. The risk-free rate typically

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[61] Exh. No. 351 at 50:Table 1 (Hill).
[62] Public Counsel Initial Brief at 33.
[63] Mr. Hill notes that in more than twenty years of testifying on the issue of cost of equity capital he had never encountered a DCF based solely on stock price growth. Exh. No. 351 at 48.
[64] Exh. No. 206C at 40:2-3 (Cicchetti).
[65] Public Counsel Initial Brief at 9, 33; Staff Initial Brief at 15.
[66] Unfortunately, the term "market premium" is used somewhat interchangeably with the term "equity premium." We encounter this in the testimony, exhibits, and briefs in this proceeding. In this Order, we will use the terms consistently. Referring to the CAPM equation $K_n = R_f + B_n (R_m - R_f)$ we will refer to R_m as the "market premium" and to the result of $(R_m - R_f)$ as the "equity premium."
[67] The broader market Beta, set at one, establishes the benchmark around which relative risk is measured. Beta less than one is less risky than the broader market; greater than one is more risky than the market.

is determined from the market for investments such as United States Treasury notes or bonds. Whether short term, intermediate term, or long term Treasuries are selected depends in part on the nature of the investment under consideration, and whether one wishes to evaluate short, intermediate, or long term investments. Finally, the equity premium, like the growth rate in DCF analysis, attempts to measure investors' expectations regarding the return on the market portfolio above that of the risk-free rate.

53 CAPM analysis requires judgment in determining the appropriate Beta, risk-free rate, and market premium. Dr. Cicchetti decided not to rely on published third-party sources, but rather calculated his own Beta for the Company by analyzing its performance using quarterly data over the past three years.[68] Dr. Cicchetti calculated a Beta of 0.62807, suggesting that PSE is a relatively low risk investment relative to the broader market.[69] Dr. Cicchetti used the 30-year Treasury bond yield of 4.89% for his risk-free rate.[70] For market premium Dr. Cicchetti used 17.8%, an annualized average return for the Dow Jones Industrial Average since 1993.[71] Thus, the three elements in Dr. Cicchetti's CAPM estimate cover three different lengths of time: 30 years for the risk-free rate, 10 years for the market premium, and three years for Beta. Dr. Cicchetti's CAPM analysis produced a return on equity for the Company of 12.998%.[72]

54 Public Counsel argues that the normal analytical approach in determining market risk premiums is to use a very long time period. This eliminates the effects of short-term volatility. Mr. Hill testified that Ibbotson Associates, a respected source of historical return data, has stated its view that by selecting shorter time periods "the analyst can justify any number he or she wants."[73]

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[68] Exh. No. 201 at 38:3-6 (Cicchetti).
[69] It is axiomatic that investors in lower risk companies tend to require less return than do investors who seek out higher risk companies.
[70] Exh. No. 201 at 38:18 – 39:1 (Cicchetti).
[71] *Id.* at 39:18-20 (Cicchetti).
[72] ROE(PSE) = 4.89% + .62807(17.8% – 4.89%) = 12.998% (per Exh. No. 201 40:12-15 (Cicchetti)).
[73] Exh. No. 351 at 55 (Hill).

Illustrating the point, Public Counsel compares Dr. Cicchetti's market risk premium, 12.91%, to the 5% to 6.6% market risk premium that Ibbotson Associates reports has existed over the past 77 years.[74] Public Counsel argues that Dr. Cicchetti has "cherry picked" the periods from which his data are derived to produce the results he seeks.

55 Dr. Cicchetti's third, and final, cost of equity analysis used the risk premium methodology. Return is measured under this approach as the sum of (i) a risk-free interest rate, (ii) a corporate debt risk premium and (iii) a component to reflect equity risk.[75] Dr. Cicchetti again used the 30-year Treasury bond, at 4.89%, for his risk-free rate. He turns to the literature and concludes, on the basis of two articles published by the same two authors seven years apart during the 1990's, that a risk premium spread of between 7.14% and 7.54% is appropriate, deriving a range for equity return of 12.03% to 12.43%. How these authors determined their proposed risk premium is unclear from Dr. Cicchetti's testimony. It is also unclear whether their results are useful when evaluating a company such as PSE.

56 Mr. Hill apparently did examine this question. He testified that:

> The studies on which Dr. Cicchetti relies for his risk premium analysis are based on the cost of equity capital of a broad market measure (the S&P 500), not on the cost of capital of utility operations. Therefore, the 12% cost of capital estimates he provides (even if we assume his "updating" of the risk premiums is accurate) is that of unregulated, industrial operations not the cost of capital of a combination electric/gas utility operation. Utility operations are significantly less risky than the S&P 500, and Dr. Cicchetti's Risk Premium results, which are based on the cost of

[74] Public Counsel Initial Brief at 37 (citing Exh. No. 363, (Hill)).
[75] Exh. No. 201 44:4-6 (Cicchetti).

equity of the latter, should not be considered a reliable estimate of the cost of equity of the former.[76]

57 Mr. Hill testified that if Dr. Cicchetti's Risk Premium is adjusted so that it provides an equity cost estimate for utilities rather than the unregulated industrial firms in the S&P 500 Index, that analysis provides a cost of equity indication for Puget of 9.38%.[77]

58 Dr. Cicchetti relied on CAPM and Risk Premium analyses as a check of his DCF results. Given that we accord little weight to Dr. Cicchetti's DCF results, his CAPM and Risk Premium analyses stand for very little. Moreover, we find the criticisms leveled at these analyses, as performed by Dr. Cicchetti, also have merit. We find we should give little weight to the results Dr. Cicchetti reports on the basis of his CAPM and Risk Premium analyses. We turn now to the cost of equity analyses presented by Dr. Wilson and Mr. Hill.

59 Staff's witness, Dr. Wilson, also relied substantially on DCF theory in reaching his return on equity recommendation. Dr. Wilson used the same combination electric and gas utilities that Dr. Cicchetti identified as being most comparable to PSE. He calculated historic dividend growth and projected earnings growth for each of those companies and for PSE.[78] Combining these growth estimates with the dividend yields reported in Standard & Poor's most recent Monthly Stock Guide, Dr. Wilson found a range of equity returns from 6.6% to 8.9% for the comparable companies, with an average of 7.8%. The range Dr. Wilson found for PSE standing alone was 6.7% to 10.4%.[79]

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[76] Exh. No. 351 at 59 (Hill). We note that Dr. Cicchetti calculated a Beta of .62807 for PSE that shows it to be significantly less risky than the broader market.
[77] *Id.* at 60 (Hill).
[78] Exh. No. 481 at 13:10 to 14:6 (Wilson). Historic dividend growth was calculated over ten years through 2003. Projected dividend growth reflected the forecast period between 2003 and 2008 as projected by Value Line Investment Survey and IBES. Exh. No. 481 at 15: 8-13 (Wilson).
[79] Exh. No. 481 at 15:13-17 (Wilson) and Exh. No. 484.

60 Dr. Wilson also performed a "fundamental" DCF calculation as an alternative means of estimating PSE's cost of equity.[80] That analysis produced a return on equity estimate of 8.63%, with individual company results ranging from 6.7% to 9.5%. Dr. Wilson determined that PSE's fundamental DCF return on equity as a stand-alone company is 8.3%.[81]

61 As a check on the results of his DCF analyses, Dr. Wilson also performed a CAPM analysis. Dr. Wilson used a short-term (*i.e.*, 90 day) U.S. Treasury bill as the measure of a risk-free investment. Dr. Wilson testified that such securities are commonly used for this purpose because they have little or no default or inflation price risk.[82] Such bills yielded approximately 1.7% at the time Dr. Wilson performed his study.[83] Dr. Wilson used the average Beta value of 0.825% for the comparable companies studied by both Staff and PSE in their DCF analyses.[84] Dr. Wilson turned to the literature for his equity risk premium of 7%, which, he testifies, is supported by recent surveys and academic studies that show the equity risk premium is in the range of 3 to 7%.[85] Dr. Wilson's equity risk premium implies a market risk premium of 8.7%. Thus, Dr. Wilson's CAPM estimate of the cost of equity for PSE is:

$$K = 1.7\% + 0.825\ (8.7\% - 1.7\%) = 7.48\%$$

a level Dr. Wilson considers as confirmation of his 8 to 9% cost of equity recommendation.

62 Public Counsel's cost of capital witness, Mr. Hill, performed a DCF analysis, a CAPM analysis, a Modified Earnings-Price Ratio (MEPR) analysis, and a Market-

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[80] A fundamental DCF calculation uses retained earnings as a measure of future dividend growth. Exh. No. 481 at 16:10-17 (Wilson).
[81] *Id.* at 17:8-12 (Wilson) and Exh. No. 485.
[82] *Id.* at 18:10-12 (Wilson).
[83] *Id.*at 20:1-3 (Wilson).
[84] *Id.*at 22:1-3 (Wilson) and Exh. No. 487.
[85] This includes studies that show that the equity risk premium is no more than 3 to 5 percentage points above Treasury Bills and *Id.* at 20: 3 to 21:19 (Wilson).

to-Book Ratio (MTB) analysis. He developed a range of current equity capital costs for electric utilities similar in risk to PSE of 9.00% to 10.00%. In assessing the results of his analyses, Mr. Hill stated:

> Averaging the lowest and the highest results of the corroborative analyses (CAPM, MEPR, and MTB) produces an equity cost rate range of 8.83% to 9.41%—a range that encompasses the DCF result. The other corroborative analyses indicate that my DCF results provide an accurate estimate of the cost of common equity of electric and gas utilities.[86]

63 Mr. Hill testified that, considering a range of relevant factors, his best estimate of the cost of equity capital for firms similar in risk to PSE is in the range of 9% to 10%.[87] Mr. Hill concluded that Puget's equity return should be 9.75%, in the upper half of this range, due to financial risk differences between Puget and his sample group of companies.[88] In addition, Mr. Hill took into account the fact that, if the economy continues to expand, interest rates are likely to increase slowly over the next few years.

64 Mr. Hill used proxy companies for measuring the dividend yield for PSE because the Company has no publicly traded stock.[89] Mr. Hill's proxy group consisted of thirteen publicly held fully-integrated electric and gas combination utility companies. Mr. Hill selected these electric companies from Value Line, a publication that provides information concerning investors' expectations.[90] These combination electric and gas companies have a continuous financial history with at least 50% of operating revenues generated by electric utility operations. Mr. Hill did not include companies that were in the process of merging or of being acquired, or that had realized an upward stock price shift

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[86] Exh. No. 351at 40- 41 (Hill).
[87] *Id.*
[88] *Id.* at 43-46 (Hill).
[89] We note that PSE's parent, Puget Energy, is among the 13 companies in Mr. Hill's set of comparables.
[90] Exh. No. 351 at 32 (Hill).

due to merger or acquisition. The companies in Mr. Hill's sample group also had bond ratings from at least one major rating agency ranging from "BBB-" to "BBB+", a stable book value, and no recent reductions in dividends.

65 Mr. Hill checked his sample of companies to ensure that they have similar or greater risk than Puget, using Standard & Poor's business profile rankings.[91] Mr. Hill testified that the average business risk position of his sample companies is 5.75.[92] By that measure, Mr. Hill's sample companies have greater business risk than Puget. As the Commission learned from Company witness Donald Gaines, PSE recently received an improved business profile score of 4 on the Standard & Poor's scale, moving from its prior position of 5.[93] At the time of Mr. Hill's analysis, Puget also had a higher price/earnings ratio and a better ranking with regard to buy and sell recommendations of analysts than did his sample group.[94]

66 To determine the dividend yield for his selected proxy companies, Mr. Hill first estimated, and then annualized the next quarterly dividend payment of each firm in the proxy group.[95] Mr. Hill adjusted the quarterly dividend amounts for a few companies in the proxy groups based on information that these companies would raise their dividends in the future. Mr. Hill identified the average monthly dividend yield for the companies in his sample group as 4.66%.

67 To determine the growth rate of the dividends for the proxy groups, Mr. Hill used historic and projected growth rates emphasizing recent trends. Mr. Hill evaluated five-year sustainable growth rates, including retention ratios, equity returns, book values per share, and the number of shares outstanding. Regarding forward-looking growth rates, Mr. Hill considered Value Line's three-

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[91] Exh. No. 351at 33 (Hill), Exh. No. 345 (Lazar).
[92] Exh. No. 351at 33.
[93] TR. 475:19-22; TR. 477:22 – 478:11.
[94] Public Counsel Initial Brief at 27.
[95] Exh. No. 351at 38, 39 (Hill).

to five-year projected growth in earnings, dividends, book value, and sustainable growth.[96]

68 The result of Mr. Hill's growth rate analysis was an average investor-expected growth rate of 4.66%. Public Counsel argues that when compared to published growth rates available to investors, Mr. Hill's growth rate estimate is on the high side. The average of Value Line's 3- to 5-year projected earnings, dividends and book value growth for the companies in Mr. Hill's sample group is 3.35%. This is more than 100 basis points below Mr. Hill's long-term growth estimate. Public Counsel also states that the average earnings growth projection of investment analysts from First Call (IBES) is 4.07%, also considerably lower than Mr. Hill's DCF growth rate estimate[97]. Mr. Hill's DCF result for his combination electric and gas utility sample group is 9.32%.[98]

69 Mr. Hill performed CAPM analyses to test his DCF results. He used both the T-Bill and long-term Treasury bond yields for his risk-free rate.[99] Mr. Hill used arithmetic (6.6%) and geometric (5.0%) averages of equity risk premiums related to long-term Treasury yields.[100] Mr. Hill used a Beta coefficient taken from Value Line, the average of which for his electric and gas proxy group is 0.76.[101]

70 Applying the CAPM formula, Mr. Hill multiplied the overall arithmetic average equity risk premium of 6.6% by the Beta coefficient of 0.76 to determine the sample group risk premium of 5.00%.[102] This represents the electric and gas utility risk premium that Mr. Hill added to the risk-free T-Bond rate of 5.15%, which yields a common equity cost estimate of 10.15%.[103]

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[96] Exh. No. 351 at 34-38 (Hill).
[97] Exh. No. 360 at 2 (Hill).
[98] Exh. No. 351 at 39, (Hill).
[99] *Id.*, at 4.
[100] *Id.* at 5.
[101] *Id.*; Exh. No. 363.
[102] Exh. No. 355; Exh. No. 363.
[103] *Id.*

71 Mr. Hill, as noted above, also performed MEPR and MTB tests. These, too, supported his DCF results.[104]

72 Mr. Hill noted that in establishing a range of common equity costs for ratemaking purposes it is reasonable to recognize that investors expect interest rates to increase somewhat over the next few years. For that reason, Mr. Hill estimated an appropriate range of equity capital cost rates for electric utilities that are similar in risk to Puget ranges from 9.0% to 10.0%. The mid-point of that range, 9.5%, is similar to but higher than Mr. Hill's DCF result of 9.32%.

73 In summary, we focus on the DCF analyses presented by Dr. Wilson and Mr. Hill as the most substantial and reliable evidence of PSE's cost of equity capital at this time. As previously discussed, Dr. Wilson performed both a "traditional" and a "fundamental" DCF analysis using the same set of 11 comparable companies used by Dr. Cicchetti. Dr. Wilson's traditional DCF used dividend growth to measure the growth component of the DCF method. His "fundamental" analysis used both dividend and retained earnings to measure growth. Dr. Wilson's traditional approach produced ROE estimates of 6.7% to 10.4% for PSE.[105] His fundamental approach produced an ROE for PSE of 8.3%.[106]

74 We give some weight to Dr. Cicchetti's criticism of Dr. Wilson's DCF analysis on the basis that it includes negative dividend growth rates. PSE states that applying dividend growth rates reported by the Institutional Brokers' Estimate Service (IBES),[107] Dr. Wilson concludes that the average ROE for his group would be 7.77%.[108] PSE argues that if "traditional" DCF analysis is performed using only the three utilities from the group that do not have negative dividend growth or zero dividend, the average ROE would be 150 basis points higher or 9.27%.[109]

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[104] Public Counsel Initial Brief at 30-31.
[105] Staff Brief at 14
[106] *Id.* at 15
[107] Exh. No. 483. IBES is an independent service that gathers and compiles the different estimates made by stock analysts on the future earnings for the majority of U.S. publicly traded companies.
[108] Exh. No. 484.
[109] PSE Initial Brief at 21 (citing Exh. No. 206C at 46:3-14 (Cicchetti)).

75 PSE also criticizes Dr. Wilson's analyses because he applies a different "fundamental" DCF analysis to Dr. Cicchetti's list of comparable companies that increases his group's average ROE to 8.63%.[110] However, in this analysis, PSE states, Dr. Wilson uses dividend growth rates projected by Value Line that are lower than the IBES growth rates he used in his "traditional" DCF analysis. PSE argues that if Dr. Wilson had instead used the same projected growth rates provided by IBES that he used in his "traditional" DCF analysis, the resulting ROE under his "fundamental" DCF would be 10.8%.[111]

76 Finally, PSE argues that as with his "traditional" DCF analysis, Dr. Wilson's "fundamental" analysis errs in applying a DCF analysis that utilizes dividend growth rates of the Company and other utilities in Dr. Cicchetti's comparables group that have negative dividend growth or zero dividends.[112] PSE states that applying Dr. Wilson's "fundamental" DCF analysis and Value Line dividend growth rate projections to the three utilities from the sample group that do not have negative dividend growth or zero dividends, the average "fundamental" DCF ROE would be 9.3%.[113] If, however, the IBES growth rate were used in Dr. Wilson's "fundamental" DCF model for these three utilities, then the average ROE increases to 11.33%, according to PSE.[114] In summary, according to Dr. Cicchetti, Dr. Wilson's "traditional" and "fundamental" DCF analyses would yield results between 9.27% and 11.3%, if corrected for errors Dr. Cicchetti posits in his critique.[115]

77 Although PSE levels various criticisms at Mr. Hill's analysis largely related to his choice of comparables, the salient fact is that Mr. Hill's results closely match those achieved by Dr. Wilson, who used the same comparables as PSE. Mr. Hill's

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[110] *Id.* (citing Exh. No. 481 16:5 – 17:12 (Wilson); Exh. No. 485).
[111] *Id.* at 21 (citing Exh. No. 206C 47:13-15 (Cicchetti)).
[112] *Id.*
[113] *Id.* (citing Exh. No. 206C 47:16-18 (Cicchetti)).
[114] *Id.* (citing Exh. No. 206C at 47:18-20 (Cicchetti)).
[115] PSE Brief at 21-22

results, at the very least, tend to confirm Dr. Wilson's results. Mr. Hill's DCF yields a range from 8.07% to 10.85% with an average of 9.32%.[116]

78 In addition to the traditional financial analysis and disagreements among the expert witnesses about inputs and methods used in those analyses, our record contains other evidence pertinent to the cost of equity. Both the Company and Public Counsel cite the energy utility equity awards granted by commissions in other states as useful information.[117] The simple average of equity returns granted by state commissions in more than 50 cases between January 2003, and June 2004, is 10.9%.[118] The Company cites this fact as evidence that the recommendations of Staff and Public Counsel are too low because they are "out of sync" with the equity ratios and returns on equity being set across the nation.[119] Public Counsel argues that this same information shows that the Company's proposal of 11.75% is too high because it is above the range of 10.0% to 10.5% within which it says the majority of these awards have fallen. Staff, for its part, offers that while the returns allowed in other jurisdictions "provide some guidance, a simple mathematical comparison to companies that face different circumstances in different states would be inadequate and inappropriate."[120]

79 Finally, NWIGU offers its own view of the analytic evidence presented by the expert witnesses and, in light of this evidence, recommends that a fair return on equity would fall in the high end of the ranges produced by Dr. Wilson and Mr. Hill, "with a few basis points added to the high end of that range to account for recent upward movement in interest rates above the record lows reached in 2004."[121]

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[116] See Exh. No. 363.
[117] Public Counsel Initial Brief at 24; PSE Initial Brief at 30.
[118] Exh. No. 179C.
[119] PSE Initial Brief at 30.
[120] Staff Initial Brief at 21.
[121] NWIGU Initial Brief at 13

Commission decision:

80 Establishing the proper return on equity is not a precise science; it is an exercise in informed judgment. Considering all of the competing financial analysis evidence, we find that Dr. Wilson's traditional DCF approach, suggesting at the upper end an equity return of 10.4%, is about right. We note that an equity return between 10.0% and 10.5% falls within the range of equity awards in other jurisdictions and that such a check is useful to fulfill the common sense approach NWIGU urges. While Dr. Wilson supports a lower number than what is represented by his high point, Mr. Hill points out that it is appropriate to consider that interest rates are rising and we can expect in such an environment some upward pressure on the cost of equity capital. Taking all into account, we find that PSE's cost of equity capital should be set at 10.3% for purposes of setting rates in this proceeding. Coupled with our determination to set PSE's equity share at 43.00%, the computed weighted average cost of equity is 4.43%.

2. Debt

i. Long-term Debt

81 PSE's embedded cost of long-term debt is undisputed at 6.88%.[122] We find this to be a reasonable cost. The long-term debt share to be included in PSE's capital structure turns in part on our determination of issues discussed at length in connection with equity share and cost. Given our decisions concerning the basis for and share of equity to be included in the Company's capital structure, we find the share of long-term debt is 47.53%. This results in a computed weighted average cost of long-term debt of 3.27%.

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[122] PSE Initial Brief at 5

ii. Short-term Debt

82 The Company proposes a short-term debt cost of 4.81%, with a short-term debt ratio of 3.09%.[123] Staff proposes a short-term debt cost of 4.55%, with a short-term debt ratio of 3.21%.[124] Public Counsel proposes a short-term debt cost of 4.00%, with a short-term debt ratio of 4.36%.[125] The Company's and Staff's respective proposals result in identical weighted averages of short-term debt of 0.15%, and Public Counsel's results in a weighted average of 0.17%.[126]

83 The amount and cost rate of short-term debt recommended by the Staff and Company are based on different views of PSE's capitalization over the rate-year. PSE uses end of rate-year data while Staff uses average rate-year data. Public Counsel recommends a level of short-term debt that it argues represents the actual amount of short-term debt available to PSE. Public Counsel used a lower short-term debt cost rate than PSE on the basis of its claim that there are discrepancies in the Company's method of calculating short-term debt costs. Public Counsel argues that these discrepancies were never fully explained.[127]

84 Public Counsel raises issues concerning the Company's use of Rainier Receivables. According to Public Counsel, the Commission should be concerned that it cannot effectively audit either the amount of short-term debt used by the Company, or the cost of short-term debt. In addition, Public counsel is concerned that the arrangements between PSE and Rainier Receivables are not "arms-length." Finally, Public Counsel believes that rate-making adjustments to working capital and taxes may be required based on PSE's use of Rainier Receivables to manage cash flow.[128]

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[123] Exh. No. 179C at 3:Table 3 (Gaines); Exh. No. 181C.
[124] Exh. No. 179C at 3:Table 1 (Gaines); Exh. No. 490 .
[125] Exh. No. 179C at 3:Table 2 (Gaines); Exh. No. 368.
[126] Exh. No. 179C at 35:6— 36:15 (Gaines); Exh. No. 179C at 3:Tables 1-3 (Gaines); Exh. No. 490; Exh. No. 368; TR. 402:3-7 (Gaines).
[127] Public Counsel Initial Brief at 10.
[128] Public Counsel Initial Brief at 10-14.

85 The Company objects to Public Counsel's recommendations for short-term debt because they are hypothetical and not "based on the Company's short-term debt cost." The Company argues that its use of Rainier Receivables reduces its debt costs and has been fully disclosed in this case."[129]

86 The Commission has concerns about the Company's treatment of short-term debt and the issues Public Counsel raised concerning Rainier Receivables. Public Counsel and PSE brief these issues at some length, but it is impossible to resolve their dispute on the basis of the current record. Staff did not offer argument concerning the issues raised by Public Counsel, but the Commission expects to learn more about these issues from Staff, among others, in future proceedings.

87 For purposes of setting rates in this proceeding, we find that the Company's capital structure should include 3.11% as short-term debt at a cost of 4.81%. This results in a computed weighted average cost of short-term debt of 0.15%.

3. Trust Preferred Stock

88 There is no dispute that the cost for Trust Preferred Stock is 8.60%. Slight differences among the parties in the share of Trust Preferred Stock in the capital structure are driven by their differences regarding equity share. The Commission finds on the basis of its determinations concerning equity share, as previously discussed, that the capital structure should include 6.32% of Trust Preferred Stock. This results in a computed weighted average cost of Trust Preferred Stock of 0.54%.

[129] PSE Initial Brief at 7.

4. Preferred Stock

89 There is no dispute that the cost of Preferred Stock is 8.51% with a capital share of .04%. The Commission finds this reasonable. This results in a computed weighted average cost of preferred stock of 0.00%.[130]

5. Summary

90 We summarize our determinations of the issues concerning Capital Structure and Cost of Capital in Table One.

TABLE ONE

Capital Structure and Cost of Capital Determination

Long-term Debt	47.53%	6.88%	3.27%
Short-term Debt	3.11%	4.81%	0.15%
Trust Preferred	6.32%	8.60%	0.54%
Preferred Stock	0.04%	8.51%	0.00%
Common Equity	43.00%	10.30%	4.43%
Total	**100.00%**		**8.40%**

91 Our conclusions concerning the appropriate capital structure and component cost rates produce an overall weighted cost of capital of 8.40%. Based on the evidence in our record, this overall rate of return will be sufficient to attract the capital the Company may need for infrastructure expansion while at the same time producing financial ratios measuring interest coverage and debt leverage solidly within the ranges required for BBB credit ratings by Standard & Poor's and other rating agencies. With this foundation, and considering our recent actions approving a power cost adjustment (PCA) mechanism and power-cost

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[130] Exh. No. 179C at 4:1-2 (Gaines); Exh. No. 179C at 3:Tables 1-3 (Gaines); Exh. No. 181C; Exh. No. 490; Exh. No. 368.

only rate cases (PCORC), the Company should have every opportunity, with strong management and improvements in efficiency, to further improve its credit rating and strengthen its overall financial health.

B. Revenue Requirement

92 Only PSE and Staff put on full revenue requirements cases. These parties' respective Results of Operations were provided as appendices to their Initial Briefs. PSE and Staff agree on the starting point—the Company's Actual Results of Operations during the test period for both electric and gas, except for relatively small differences in starting rate base.[131]

93 To determine rates that will apply prospectively, the parties propose various restating actual and pro forma adjustments to the test period operating revenues and deductions. Restating actual adjustments adjust the booked operating results for any defects or infirmities in actual recorded results that can distort test period earnings or adjust from an as-recorded basis to a basis accepted for rate making purposes.[132] Pro forma adjustments give effect to known and measurable changes not offset by other factors occurring during or after the test year.[133]

94 PSE and Staff agree to a starting net operating income for electric of $219,638,434. PSE proposes total adjustments to electric net operating income of ($49,321,176) while Staff proposes ($30,988,994). Thus, PSE arrives at an adjusted net operating income of $170,317,258, which compares to Staff at $188,649,439. The parties agree that electric rate base should be increased by $29,362,338.

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[131] These differences, $1,389,410 on electric (total rate base is approximately $2.5 billion) and $621,133 on gas (total rate base is approximately $1.1 billion), are a result of Staff removing from the test period rate base deferred rate case expenses that PSE previously has included in rate base as a regulatory asset. We discuss this issue in more detail below in connection with electric Adjustment 2.18.

[132] WAC 480-07-510(3)(b)(i).

[133] WAC 480-07-510(3)(b)(ii).

95 On the gas side, PSE and Staff agree to a starting net operating income of $81,455,387. PSE proposes total adjustments to net operating income of ($11,474,016) while Staff proposes ($7,393,940). Thus, PSE arrives at an adjusted net operating income of $69,981,371, which compares to Staff at $74,061,447. The parties do not agree on rate base adjustments, with PSE proposing an increase of $3,146,890 while Staff proposes a decrease of $28,165,652.[134]

96 There are both uncontested and contested adjustments. The contested adjustments, which we discuss in detail below, are summarized in Table Two—Electric, and Table Three—Gas.

TABLE TWO

Restating and Pro Forma Adjustments – Electric

Adjustment Number	Adjustment Description	Company Position	Staff Position
2.03	Power Costs	$ (58,730,987)	$ (63,315,425)
2.04	Sale for Resale	(113,651,741)	(95,699,399)
2.06	Tax Benefit of Pro Forma Interest	(9,337,425)	(7,530,496)
2.10	Miscellaneous Operating Expense	(1,573,174)	(98,086)
2.11	Property Taxes	1,679,813	2,510,356
2.18	Rate Case Expense	(157,991)	123,736
2.20	Property and Liability Insurance	(321,615)	(232,606)
2.22	Wage Increase	(2,348,089)	(1,894,612)
2.23	Investment Plan	(98,366)	(74,901)
2.25	Montana Corporate License Tax	(1,283,057)	(1,272,865)
2.30	Production Adjustment	546,289	540,136

[134] This difference results from Staff's position that the revenues, operating expenses, and rate base related to PSE's Gas Water Heater and Conversion Burner Rental Program should be removed, as discussed below in connection with gas Adjustment 2.17.

TABLE THREE

Restating and Pro Forma Adjustments – Gas

Adjustment Number	Adjustment Description	Company Position	Staff Position
2.01	Revenue and Purchased Gas	$ (1,236,133)	$ 1,110,277
2.03	Tax Benefit of Pro Forma Interest	(6,077,908)	(5,700,092)
2.07	Miscellaneous Operating Expense	106,298	635,846
2.10	Rate Case Expense	(164,617)	(164,617)
2.11	Property and Liability Insurance	(122,465)	(81,039)
2.13	Wage Increase	(1,218,086)	(932,842)
2.14	Investment Plan	(54,995)	(41,872)
2.17	Gas Water Heater Program	0	606,509
	TOTAL	**$ (8,697,906)**	**$ (4,617,830)**

97 In addition to what is portrayed above in terms of contested adjustments between PSE and Staff, ICNU introduced evidence concerning power costs and rate case expense that lead ICNU to propose adjustments to these items that are different from what PSE or Staff propose. Public Counsel, on brief, supports ICNU's proposed adjustments in both areas. NWIGU, on brief, supports ICNU on rate case expense. We frame our discussion below on the basis of the presentations by PSE and Staff, but take ICNU, Public Counsel, and NWIGU's positions fully into account in discussing the specific adjustments with which they take issue.

1. Contested Adjustments—Electric

a. Adjustment 2.03—Power Costs

98 This adjustment uses the AURORA power supply model to restate power costs for purposes of calculating a revenue requirement and establishing a new baseline rate in the Power Cost Adjustment (PCA) mechanism that we approved in Docket Nos. UE-011570, *et al.* We discuss and determine five contested components in this part of our Order. The most significant of these is the price of fuel for PSE's combustion turbine (CT) and combined cycle combustion turbine (CCCT) generation facilities.

99 It is necessary, however, that we make one general determination before turning to discussion of the individual power cost model inputs that are disputed. The power cost determinations we make here not only will be significant factors in setting rates, they also will establish a new baseline for purposes of the PCA mechanism. One significant feature of the PCA mechanism is a $40 million, four-year cumulative cap. The cap results in deferral of 99% of PSE's excess power costs after the Company has under-recovered $40 million in power costs. PSE expects the $40 million cap will be reached sometime this year, after which 99% of PSE's excess power costs will be deferred.[135]

100 The cap is set to expire on June 30, 2006, shortly after the end of the rate year.[136] When the PCA cap expires the risk dynamic between PSE's shareholders and PSE's ratepayers will change significantly. In light of this, it is important to reset the PCA power cost baseline effective July 1, 2006. This can be accomplished in a power cost only rate proceeding filed by the end of February 2006, or in the context of a general rate proceeding. The significance of this is such that we condition our approval of an adjustment to the PCA baseline in this proceeding on the requirement that PSE make an appropriate filing, by February 28, 2006, that will include examination of the PCA power cost baseline and lead to adjustment of the baseline, if appropriate under the facts developed in the subsequent proceeding.[137]

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[135] TR. 752:20-24 (Story).

[136] *WUTC v. Puget Sound Energy, Inc.,* Docket Nos. UE-011570, *et al.*, 12th Supplemental Order, Exhibit A to Settlement Stipulation ("PCA Settlement") at 2, ¶ 3 (2002).

[137] We note that the Company states it does not object conceptually to updating its gas price forecast, which is a key factor in determining power costs. PSE states that it believes in any event that the gas price forecast is likely to be updated before the expiration of the PCA cumulative cap. PSE recognizes that such an update may be effected through a general rate proceeding or a PCORC. PSE Reply Brief at 34.

i. Gas Costs

101 The interplay between the tasks of determining power costs for purposes of setting rates and for purposes of resetting the PCA baseline makes an already challenging task even more complicated. We will first consider and resolve a threshold issue, what ICNU describes as "the philosophical debate between forecasted and normalized" gas costs.[138] Put in more simple terms, the question is whether we should set the PCA mechanism power cost baseline focusing on the short and intermediate term future, as PSE and Staff contend, or on the long-term future, as ICNU advocates.

102 ICNU raised this issue in PSE's first PCORC proceeding during 2003 - 2004.[139] Although the Commission approved PSE's normalized gas costs based on NYMEX futures prices rather than ICNU's normative price derived from a fundamentals model, the Commission acknowledged that the issue deserved additional scrutiny:

> ICNU has raised important questions concerning how a baseline fuel gas price should be established for ratemaking in the context of a PCORC proceeding, and otherwise . . . . We agree with Staff that this is an issue that will grow in importance and one that requires additional scrutiny . . . . These questions should be revisited in a future proceeding. PSE's recently filed general rate case will provide an opportunity for parties to develop this issue more fully.[140]

103 In this proceeding ICNU again argues that fuel gas costs should be based on a fundamentals analysis that establishes a normative price for gas over the longer term (*i.e.,* for periods extending up to five years beyond June 30, 2006), rather

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[138] ICNU Initial Brief at 11.
[139] *WUTC v. Puget Sound Energy, Inc.*, Docket No. UE-031725, Order No. 12 (April 2004).
[140] *Id.* at ¶¶ 55-56.

than forward market prices projected to prevail during the rate year (*i.e.*, 12 months ending February 2006). ICNU argues that a fundamentals analysis more accurately reflects expected market conditions over time. That is undoubtedly true, but tautologous. Fundamentals analysis relies on *assumptions concerning future market conditions* over the longer term, while the methods used by PSE and Staff focus on the analysis of *transactional data taken from the actual futures market* for natural gas in the relatively near term. The two approaches are based on different inputs and produce results that are useful in answering different questions.

104 ICNU argues that relying on actual market data is not appropriate because the out months of NYMEX strips have very low volumes and do not represent a liquid market. PSE and Staff witnesses, however, testified that there is a good relationship between futures prices and spot prices over 12 month periods.[141] ICNU also argues that using NYMEX prices is inappropriate for establishing average costs over the long term—what ICNU misleadingly refers to as a "normalized baseline gas price"—because such prices take into account near term circumstances. In the context of utility ratemaking when we use the term "normalize" we are focused on near term circumstances—usually in this jurisdiction we normalize to a historic test year considering a rate year that is no more than 12 months into the future. Viewed in that context, the fact that NYMEX prices take near term circumstances into account is a strength, not a weakness.

105 In sum, ICNU's arguments all beg the question—what it calls a philosophical question—what do we mean to accomplish in setting the PCA baseline? The PCA was approved as an accounting mechanism with the principal goal of balancing risk associated with short-term fluctuations in market prices. That is, the Commission's purpose in approving the PCA was to protect ratepayers and shareholders from volatility in the market. Among other things, the PCA protects the public interest through cost sharing designed to mitigate against the

[141] Exh. No. 125: 6, 15-27 (Dubin); Exh. No. 82C 24:2-9 (Ryan); Exh. No. 451 29:18 – 30:2 (Mariam).

consequences of market price excursions such as were experienced during 2000 and 2001. The PCA, however, also accounts for ordinary fluctuations in price, up and down, from the anticipated price. We examine the results of this accounting on an annual basis. If our annual review demonstrates that the accumulation of deferrals has been quite high, up or down, that suggests the need to reset the baseline to a more realistic level. We do this by analyzing the best information available about what average prices can be reasonably expected over the short and intermediate terms.

106 It is important for a number of reasons that the power cost baseline be examined on a regular basis and, as the market changes, adjusted to reflect those changes. The PCA establishes a deferral account in which PSE keeps track of over recovery or under recovery of costs it experiences on a monthly and annual basis. Any recovery of excess costs, or refund of excess revenues, does not take place until a point in time after a deferral is booked. PSE must bear the cash flow consequences during periods of under recovery. If the power cost baseline is set too low relative to actual prices, the greater the burden of those consequences for PSE's shareholders. Similarly, if the power cost baseline is set too high, ratepayers are burdened by the fact that they are paying more for power than what they should be paying. The PCA mechanism was meant to be fair to both shareholders and ratepayers.

107 In summary, as we examine the power cost baseline from time to time—recognizing that it is important that we undertake that examination on a regular basis—we must strive to determine, with the greatest degree of precision that forward looking models can produce, an accurate estimate of actual costs that PSE will experience in the near and intermediate terms. It is a challenging task to estimate what the Company's actual costs of power will be in future periods, yet that is what we must strive to do so that the PCA mechanism functions, as intended, to balance the risk of excursions in power costs as equally as possible between ratepayers and shareholders.

108 We resolve the philosophical question raised by ICNU in favor of the practical conclusion that power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings.

109 Our determination to focus on the short and intermediate term—the rate year in this instance—means that the dispute we must reconcile turns on the question of what data should be relied on in applying the methodology that Staff and PSE agree is appropriate to use, at least for purposes of this proceeding.

110 In its initial filing, the Company projected the anticipated cost of gas during the rate year using the forward market prices at Henry Hub over a 10-business-day period ending January 8, 2004 as published on the New York Mercantile Exchange ("NYMEX") futures market, adjusted by a regional basis price.[142] This methodology produced an average forward price for the rate year of $4.39 per MMBtu for the Sumas market hub.[143]

111 Staff's gas price recommendation used published data from Gas Daily at the Sumas market hub to calculate a set of three-month average forward prices for the period December 2003 through April 2004. An average of the three-month average forward prices was then used to estimate a "normal" forward spot price of $4.69 per MMBtu for the rate year.[144]

112 On rebuttal, PSE stated that it accepted Staff's approach, but not Staff's decision to exclude data from periods after April 2004. The Company used a three-month average of forward prices ending September 30, 2004. This resulted in a gas price of $5.60 per MMBtu for the Sumas market hub.[145] That remains PSE's

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[142] Exh. No. 71 25:15-17 (Ryan).
[143] Exh. No. 82C 21:14 (Ryan).
[144] Exh. No. 451 at 30 (Mariam).
[145] Exh. No. 82C at 21: 11-12 (Ryan).

recommendation for purposes of setting rates in this proceeding and resetting the PCA baseline.[146]

113 Staff states that it estimated an average gas price that will prevail during the rate year on the basis of the data it selected considering that future gas prices are unpredictable because the forward market for natural gas is inefficient.[147] Staff argues that this inefficiency results from fundamental attributes of the market and commodity itself,[148] as well as non-market factors, such as the activities of speculators, that have caused extreme upward movements in gas prices that are unrelated to the supply or demand for gas.[149]

114 Staff would eliminate periods after April 30, 2004 from consideration when establishing gas costs during the rate year because such prices are, in the Staff's opinion, "biased."[150] Staff argues that empirical evidence Dr. Mariam reviewed shows sharp increases in forward prices after April 2004 that are characteristic of an inefficient market.[151] Thus, Staff argues, including forward prices beginning May 2004 would bias the average gas price estimated for the rate year.[152] For the same reason, Staff recommends against the Commission relying on responses to bench requests in which parties reran their gas price analyses for the rate year using more recent data.[153]

115 PSE states that its analysis of the relationship between NYMEX forward market prices and spot market closing prices over the 1991 through 2004 historical

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[146] We note PSE's discussion in its Reply Brief to the effect that stating a single gas price can be misleading because the determination of power costs via AURORA requires significantly more granular data. PSE states that "because gas prices fluctuate during the course of a year, and because AURORA utilizes gas price data from eight market hubs, monthly gas prices for each hub is input into AURORA in order to obtain realistic cost projections." PSE Reply Brief at 28.
[147] Staff Initial Brief at 28 (citing Exh. No. 128 at 3-14).
[148] *Id.* (citing TR. 704:12 to 705: 3 and 728:3-15 (Mariam)).
[149] *Id.* (citing TR. 703:10-13, Tr. 725:21 to 726:4, TR. 731:18 to 732:7, and 736:17 to 737:13 (Mariam)).
[150] Exh. No. 451 at 30, fn. 1 (Mariam).
[151] *Id.*
[152] Staff Initial Brief at 29.
[153] Staff Initial Brief at 29, fn. 157.

period shows that there is no statistical reason these recent months should be excluded.[154] PSE states that Dr. Dubin and Ms. Ryan considered and analyzed Dr. Mariam's claim that the post-April 2004 data should be excluded.[155] Dr. Dubin testified that he tested the data and found no bias.[156] Similarly, Ms. Ryan concluded that there was no seasonal pattern to gas prices that would indicate that April through July prices should be excluded from a gas price forecast.[157] PSE argues that the recent data Staff excluded is more informative of what prices are likely to be during the rate year.[158] PSE, citing to the bench request responses Staff urges us to not consider, says that the more recent data confirm that the Company's proposed rebuttal price is reasonable.[159]

116 Determination of an appropriate "average price" or "benchmark price" that PSE will pay for fuel gas during the rate year is an exercise in its infancy. It is no older than the PCA mechanism itself, which was approved less than three years ago. It appears from our record that some progress has been made in developing more objective approaches to the problem, and we hope that effort by Staff, PSE, and others will continue. In the meantime, however, we must determine the question based on our judgment of what data are the most indicative of the costs that PSE will incur during the rate year. But for the suggestion of market inefficiency, which would require more detailed and rigorous quantitative and qualitative analyses to confirm, the parties agree that more recent data predicts the near and perhaps even intermediate term better than older data. We find that the average price figure PSE presented through its rebuttal testimony, $5.60 per MMBtu at the Sumas hub, is appropriate to use in setting rates and in resetting the PCA power cost baseline.

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[154] PSE Initial Brief at 33 (citing Exh. No. 125 6:15-27 (Dubin); Exh. No. 82C 24:2-9 (Ryan)).
[155] PSE Reply Brief at 31.
[156] Exh. No. 451 at 30, fn.1 (Mariam); Exh. No. 125 19:18 – 23:6 (Dubin); TR. 660:5 – 661:8 (Durbin).
[157] Exh. No. 82C at 23:2 – 24:9 (Ryan).
[158] Exh. No. 125 at 21:11-13 (Dubin).
[159] *Id.* at 34 (citing Exh. Nos. 11 and 13).

ii. Coal Costs

117 Ms. Ryan testified for PSE on rebuttal that the unit cost of coal increased to $0.6122/MMBtu for Colstrip 1 & 2 and to $0.6220 for Colstrip 3 & 4.[160] Staff does not dispute these increases.[161]

118 With respect to the production cost of coal, however, Staff and PSE disagree over the price of natural gas to assume in AURORA when coal-fired generation is dispatched. Our resolution of the gas price issue resolves the only dispute between Staff and PSE on the costs of coal embedded in PSE's power costs.

iii. Oil Costs

119 PSE argues that while the AURORA model predicts hourly variable costs of serving normalized load, other costs must be added to fully capture the Company's projected power costs on an annual basis.[162] PSE proposes to include $12.75 million in revenue requirement as an external adjustment to the AURORA results to account for peaking costs.[163] This additional cost is calculated on the basis of 200 hours of oil burn during the months of November through February that PSE has assumed for the rate year at the Fredonia, Frederickson, and Whitehorn CTs.[164] PSE claims that this oil expense is a proxy for the power costs necessary to "meet load over and above the expected load, which is modeled in AURORA."[165]

120 ICNU disputes PSE's claim that AURORA does not fully account for peaking costs, arguing such costs are captured in the normalization process. ICNU argues that PSE's response to a records requisition request "conclusively

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[160] Exh. No. 82C at 25: 1-3 (Ryan).
[161] Staff Initial Brief at 30.
[162] TR. 871:24 – 872:15, 875:9-21, and 877:22 – 878:22 (Ryan); Exh. No. 101 (Ryan).
[163] Exh. No. 101; Exh. No. 102C; TR. 871:24 - 872:24 (Ryan).
[164] TR. 874:4-7 (Ryan).
[165] TR. 874:7-15 & 954:18 – 955:15 (Ryan).

demonstrates that the Company is double counting."[166] PSE's response to ICNU's allegation argues that ICNU has confused two processes used to develop proposed rates: (i) adjustments to test-year loads in order to develop pro forma revenues for the rate year; and (ii) forecasts of normalized rate-year loads in order to develop projections of power costs during the rate year.[167] With respect to the former, the Company states that it looks backward at temperatures—including extreme temperatures—and loads that have occurred to develop coefficients stating the relationship between temperature and load. PSE says it then applies those coefficients and data regarding "normal" weather to the revenues that the Company actually billed during the test year. PSE argues that the process for normalizing actual, historic test-year loads to develop pro forma revenues does not support the proposition that anything other than normal temperatures are used to project rate year power costs in AURORA.

121 Staff argues that in a normal year, PSE would not burn 200 hours of oil, thus, the additional variable costs PSE claims should not be reflected in power costs.[168] ICNU argues similarly that it is not reasonable to assume that PSE is going to experience loads that will necessitate this 200 hours of oil burn each winter, "especially when it comes at a cost of $12.75 million per year to ratepayers."[169] ICNU and Staff argue that if the Company did burn oil during a peak event, the oil costs would flow through the PCA anyway as a variable fuel cost. ICNU and Staff argue that for these reasons, the Commission should disallow all of the $12.75 million in oil costs that PSE seeks to recover in rates. If the Commission does allow the oil costs, says ICNU, then the cost of gas to serve that same load should be removed.[170]

122 As previously discussed, the goal in this proceeding is to include in rates power costs that take into account the costs expected to be incurred during the rate

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[166] ICNU Initial Brief at 15 (citing Exh. No. 108).
[167] PSE Reply Brief at 36-37.
[168] Staff Initial Brief at 31.
[169] ICNU Initial Brief at 14.
[170] *Id.* at 16.

period. Based on the available evidence, it appears there is a need to include some amount for peaking costs that are not included in the AURORA output. However, we find that the evidence does not support PSE's proposal to use 200 hours of oil-burn as a reasonable proxy measure of such costs. PSE itself points out that it could burn oil in its CTs, purchase gas to burn in its CTs, or purchase power in the wholesale market to serve its peak loads.[171] Presumably, PSE would take the least-cost option and, indeed, the oil burn over ten years from 1994 through 2003 averaged closer to 60 hours than 200 hours—with wide variation among plants.[172]

123 We set aside PSE's assumed 200 hours of oil-burn and instead limit the company's oil cost recovery to the historical use of the peaking plants averaged over the period 1994-2003. PSE calculated this amount at $3.87 million.[173] We emphasize that this amount is an estimate based on use of the average operation of the Company's peaking plants as a proxy. PSE may have incurred peaking costs for resources or purchases other than from oil fired generations over that 10 year period. Our record is not definitive on this point. Given this uncertainty, we find that ICNU's recommendation to net the cost of gas for peak loads that may be included in the AURORA results is not necessary for purposes of this estimate of additional peaking costs. In the Company's next rate case, the Commission expects a more thorough discussion of the calculation and inclusion of any peak power costs that may not be accounted for in the AURORA model.

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[171] PSE Reply Brief at 35.
[172] Exh. No. 103C at 4; Affidavit of Julia M. Ryan ¶¶ 4-5, Exh. A (Dec. 30, 2004).
[173] PSE Reply Brief at 35, fn. 183.

iv. Hydro Normalization

124 PSE initially proposed to use 60 water years to model forecasted hydroelectric generation during the rate year.[174] The Company supported its proposal with statistical analyses performed by Dr. Dubin who testified on the basis of his findings that the entire 60-year period of data from 1928-1987 should be used to forecast projected generation during the rate year.[175] Dr. Mariam, for Staff, performed statistical analyses similar to those of Dr. Dubin and reached a similar result, finding that the data are normally distributed and show no trend.[176]

125 Staff, however, disagreed with the use of the full 60 years of stream flow data because the "rule curves" that the Northwest Power Pool and federal agencies such as BPA develop and apply to run off volumes to account for the multiple uses to which the rivers are put are not yet available for the most recent 10 years.[177] Thus, Staff recommended that we rely on data from the period 1928-1977 in this proceeding.[178] The Company agreed to use this 50-year period in projecting power costs for the rate year, for purposes of this case.[179]

126 ICNU and Public Counsel argue that the Commission should retain the hydro normalization methodology it adopted in PSE's 1992 - 1993 rate proceeding because PSE and Staff have not satisfied the requirement in the Commission's 1993 order to demonstrate that the 40-year rolling average should be abandoned in favor of an alternative methodology. Public Counsel quotes from the Commission's prior order as follows:

> The Commission accepts the Commission Staff position, and directs the Company to continue to use a 40-year rolling average. The Commission believes that the parties spent far too much time

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[174] Exh. No. 111 at 5:4-13 (Dubin).
[175] Exh. No. 111 5:8-11 (Dubin).
[176] Exh. No. 451 25:1-2 (Mariam).
[177] Exh. No. 451 20:1 – 21:3 (Mariam).
[178] Exh. No. 451 20:20 – 21:3 (Mariam).
[179] Exh. No. 82C 13:8-10 (Ryan).

> revisiting this issue. They repeated arguments and evidence they have presented in previous rate cases. [Staff witness] Mr. Winterfield's presentation in Docket No. U-89-2688-T demonstrated convincingly that the cumulative error would be less under a 40-year rolling average than under the Company's proposal. While a rolling average may not be the most precise estimate, errors tend to offset one another as the method is applied over time. The evidence presented in this proceeding does not persuade the Commission that hydro availability is subject to cycles or trends. The Company is put on notice that this will remain the Commission's position on this issue unless and until a clear and convincing argument supports a superior alternative.[180]

127 The Commission's 1993 order required a "clear and convincing *argument*" as a prerequisite to changing the 40-year rolling average methodology adopted in that case. This is not tantamount to establishing a legal standard for evidence, as ICNU and Public Counsel argue. It simply is not true, as Public Counsel would have the Commission believe, that the Commission established a "standard for the future [that would] put the debate to rest."[181]

128 As the Commission's 1993 order states, the basis upon which it found the 40-year rolling average to be superior to other approaches was Staff's evidence in a prior case that the rolling average produced less cumulative error than other approaches.[182] There is no evidence that Staff analyzed in those cases the statistical validity of the underlying stream-flow data as it did in this proceeding. We now have before us a detailed analysis, performed by Dr. Mariam, that confirms not only that the 50-year stream-flow data is trend-less and normally distributed, but also that there is a high degree of correlation between streamflow and hydro generation.[183] Moreover, Dr. Dubin testified to the well-

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[180] *WUTC v. Puget Sound Power & Light Co.*, Docket Nos. UE-921262, *et al.*, 11th Supplemental Order at 43 (1993).
[181] Public Counsel Initial Brief at 108.
[182] WUTC *v. Puget Sound Power & Light Co.*, Docket Nos. UE-921262, *et al.*, 11th Supplemental Order at 43 (1993).
[183] Exh. No. 451 at 21-22 (Mariam) and Exh. No. 454.

recognized statistical theorem that use of rolling averages may produce cycles that are not actually present.[184] Dr. Mariam agreed that this problem is inherent to models that rely on rolling averages and is one reason to move away from the 40-year rolling average approach to hydro normalization.[185]

129 It also does not appear from our record that the Commission in the prior case was presented with evidence that takes into account the competing non-generation uses of the Columbia River System that restrict the use and flow of water for power generation. Again, Dr. Mariam performed such an analysis in this case through Staff's use of estimated water run-off volumes, which capture the inherent variability of water use.[186] It is significant that no one challenged the merits of Dr. Mariam's analyses on either statistical or non-statistical grounds. Neither ICNU nor Public Counsel presented evidence to show that the 40-year rolling methodology produces less cumulative error than the methodology Dr. Mariam used or is in any other way superior to what Staff proposes.

130 We find on the basis of the current record and the clear and convincing argument by Staff and PSE that the method presented by Dr. Mariam, based on 50 years of data, is a superior alternative to the 40-year rolling average.

131 We are mindful, however, of Dr. Dubin's testimony that all available data should be examined, and Mr. Schoenbeck's testimony that the Commission should use all available 120 years of available data if it elects not to use the 40-year rolling average.[187] In this case, ICNU did not demonstrate that data for the period 1879 to 1928 was verified or verifiable. Nor did it suggest a detailed methodology for using such data, which would take into account such factors as the non-generation uses of the river system. We encourage the parties to continue their

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[184] TR. 642:14 – 643:11 (Dubin).
[185] TR. 718:3-23 (Mariam).
[186] Exh. No. 451 at 13:1-11 and 23:6-16 (Mariam).
[187] ICNU Initial Brief at 18.

discussions of this subject and their efforts to develop even more rigorous tools for hydro normalization.

v. Transmission Costs/Wheeling

132 PSE pays BPA to transmit power from Company generation sites and points of purchase or exchange.[188] PSE's initial filing proposed to adjust wheeling costs based on the Company's estimate that BPA's transmission rates would increase during the rate year by $2.2 million, or 15%.[189] The Company states that it updated its estimated increase in transmission expenses based on the outcome of settlement discussions in BPA's 2006-07 transmission rate case.[190] On December 6, 2004, BPA Transmission Business Line (TBL) offered a proposed settlement to TBL's individual customers and umbrella organizations.

133 Under the terms of the TBL Rate Case Settlement Agreement, the IR Rate, the rate at which the Company receives the vast majority of its transmission service from BPA, will increase 17.7%, which increases power costs by $2.5 million.[191] PSE argues that this increase should be reflected in its power costs because, if BPA or the FERC rejects the TBL Rate Case Settlement Agreement, that would result in higher, not lower, transmission rates.[192]

134 Staff argues that there should be no adjustment from test period wheeling costs because any increase, including what PSE proposes on the basis of the pending settlement agreement, is not final and is, therefore, not known and measurable.[193] Staff disputes PSE's assertion that if the settlement is rejected by BPA or the FERC then transmission rates would necessarily be higher. Staff argues that in the event the settlement fails, the transmission rate case would go into litigation

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[188] Exh. No. 451 at 35:7-8 (Mariam).
[189] Exh. No. 82C at 14:20-21 (Ryan).
[190] PSE Initial Brief at 37 (citing Exh. No. 82C 14:16 – 15:12 (Ryan)).
[191] Exh. No. 107.
[192] PSE Initial Brief at 37 (citing TR. 963:16 – 964:10 (Schoenbeck)).
[193] Staff Initial Brief at 34-35.

mode.[194] Staff concedes that the TBL might propose higher transmission rates, but argues that any such proposal would be subject to challenge by other parties, and would not become effective in any event until approved by BPA and FERC. Until all such events play out, Staff argues, any increase in BPA wheeling charges remains unknown and unmeasurable.

135 Just as we cannot be certain of precisely what gas costs PSE will incur during the rate year, we cannot be precisely sure what increased transmission costs the Company will face. It does seem clear, however, that there will be some increase in BPA's transmission rates during the rate year. The parties' responses to Bench Request No. 10 show that there is widespread customer support for the settlement agreement. BPA's press release of January 26, 2005, states that BPA's administrator "said the settlement will expedite the transmission rate case, sparing the region a lengthy, costly formal rate process."[195] It does not appear that approval from the BPA administrator is seriously in doubt.

136 We find on the basis of the record that it is more likely than not that PSE will experience higher transmission costs during the rate year at approximately the level it requests. AURORA accounts for any offsetting adjustments that may result in power costs due to the effect within the model of higher transmission rates. Accordingly, we find that PSE's proposed change is within the known and measurable standard and should be approved.

vi. Result of Findings

137 Taking all of the above determinations related to power costs into account, the Commission finds that this adjustment decreases NOI by $53,032,522.

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[194] Staff Reply Brief at 12.

[195] PSE Response to Bench Request No. 10 (BPA Press Release dated January 26, 2005).

b. Adjustment 2.04—Sales for Resale

138 This adjustment depends on the assumptions used in the AURORA model for the power cost adjustment. The amount of this adjustment "falls out" from our determinations of the issues discussed above under the heading "Adjustment 2.03." The Commission finds that this adjustment decreases NOI by $113,651,741.

c. Adjustment 2.06—Tax Benefit of Proforma Interest

139 This adjustment is a tax benefit associated with the interest on debt used to support rate base and construction work in progress that has associated tax deductible interest.[196] Staff and the Company use the same rate base method to calculate the tax benefit of pro forma interest.[197] This adjustment depends entirely on our determinations in other parts of this Order of rate base and the weighted cost of debt to be applied to rate base. There is a corresponding adjustment on the gas side: Adjustment 2.03.

140 The Commission finds this adjustment decreases NOI by $8,124,355.

d. Adjustment 2.10—Miscellaneous Operating Expenses

i. Incentive/Merit Pay and Associated Payroll Taxes

141 PSE argues that this adjustment should be based on actual incentive plan payments earned during the test year (*i.e.*, $3,440,174). PSE states that the test period amount is less than the most recent five year and three year averages.[198]

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[196] Exh. No. 231 at 9:11-15 (Story).
[197] Exh. No. 423C at 8 (Russell); Exh. No. 238C at 11 (Story); PSE Brief at 38; Staff Brief at 35.
[198] PSE Brief at 38-39 (citing Exh. No. 333 at 2:13-3:5 (Hunt); TR. 809:19-810:8 (Parvinen)).

142 Staff argues that the 2004 payout for performance during 2003 (*i.e.*, $2,096,420) should be the starting point, with a further adjustment to remove 40% of the amount Staff argues is tied directly to PSE's earnings.[199] Staff also argues that it is appropriate to allow a relatively low amount for recovery in rates given Staff's informed belief that PSE will not achieve its earnings target for calendar year 2004, will make no payout during the rate year. On this basis, Staff argues, PSE could be denied any recovery in rates for incentive payments.[200] Staff opposes the use of multi-year averages because PSE's incentive plans have changed repeatedly and significantly over time.[201]

143 PSE counters that the amount paid in 2004, for performance in 2003, is the lowest payout in the past five years.[202] In addition, PSE argues that while there is an earnings goal threshold that must be met before any incentive payout, the Company's plan focuses on goals that directly benefit ratepayers such as customer service, service quality, safety, reliability, and efficient operations.[203] According to PSE even if the earnings goal threshold is met, if the Company's service thresholds are not met, there is no payout on the earnings goal.[204] Finally, PSE argues that even if a $0 payout during 2005 is averaged in, the six year average would be $4,189,542, and the four year average would be $2,870,831, both significantly higher that what Staff advocates.

144 While PSE incentive plans have changed over time, this appears in part to be in recognition of direction from the Commission that such plans should be tied to performance and not simply to earnings. We find that while a portion of PSE's incentive plan payments turn on the Company reaching certain earnings goals, there is a second threshold for such payments that is based on service quality, safety, and reliability considerations. These are the criteria we have looked for

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199 Staff Brief at 36 (citing Exh. No. 441 at 12 (Parvinen); Exh. No. 443 at 7; and Exh. No. 423 at 12).
200 Staff Brief at 36 (citing TR. 604:7-14 (Hunt)).
201 Staff Brief at 36 (citing TR. 815:2-11; 817:15-20).
202 PSE Brief at 39 (citing Exh. No. 333 at 2:20-21, 3: chart (Hunt)).
203 PSE Brief at 39 (citing Exh. No. 333 at 4:12-17 (Hunt); Exh. No. 335 at 11-12 (Hunt)).
204 PSE Brief at 39 (citing Exh. No. 333 at 6:2-3 (Hunt); Exh. No. 335 at 3 (Hunt)).

in authorizing, or not, the recovery of incentive payment costs. Since they are present here, we find it is not appropriate to disallow a portion of the costs as Staff advocates.

145 On the question of the appropriate amount to include, the evidence does exhibit significant variation from year to year. On balance, we find that the best estimate is one based on the four year average, taking into account that it is more likely than not that there will be a $0 payout in 2005 for performance in 2004 because the Company will not show earnings of $1.50 per share during 2004. The four year average is $2,870,831.

146 The Commission finds that the amount of this adjustment is an increase to NOI of $415,054. The Commission accordingly recalculates the payroll tax portion of the adjustment to increase NOI by $29,054.

ii. Deloitte Fee for Income Tax Advice

147 Although a relative straightforward issue when considered in isolation, this aspect of Adjustment 2.10 is complicated because it implicates other matters drawn in by the parties via testimony and in arguments made on brief. We will discuss here all of the relevant subjects, including matters related to Montana Corporate taxes and property taxes.

148 The amount directly at issue here as part of the Miscellaneous Operating Expenses adjustment is an $812,196 fee that PSE paid to Deloitte during the test year for a study upon which PSE claimed a federal income tax deduction resulting in a $72 million deferred tax balance. The deduction resulted in Federal Income Tax and Montana Corporate License Tax refunds that were accrued during the test period. PSE states that the associated federal income tax benefits in this proceeding produce approximately $10 million combined gas and electric revenue requirement savings.[205] That is not disputed. PSE also acknowledges a restating adjustment by which it removed from the test period a $1.9 million refund of the Montana tax that is related to the Deloitte Fee.

149 PSE argues, in effect, that the Deloitte payment should be treated as a normalized expense for tax advice, which is an "ongoing expense because tax law and regulatory interpretations are constantly subject to change."[206] PSE states that it should continue to recover in rates sufficient funds to engage consultants such as Deloitte in the future. PSE considers the $812,196 it paid to Deloitte to be the amount that represents "sufficient funds" for this purpose.

150 Staff argues the Deloitte fee is a non-recurring cost associated with a one-time refund and, therefore, should be disallowed for ratemaking purposes. Staff states that disallowance also would be consistent with PSE's restating adjustment that removed the Montana Corporate License Tax refund. Staff accepted this restating adjustment in conjunction with its decision to remove the Deloitte fee.[207]

151 Staff argues in the alternative that if the Commission determines that the Deloitte fee is reasonable for ratemaking purposes, the Commission should spread the cost over the 20-year tax life of the benefits.[208]

152 We find in determination of these arguments that PSE should be allowed to recover in rates some amount in recognition of the expenses the Company incurs in hiring income tax consultants in appropriate circumstances. Based on the evidence, including discussion at hearing, it appears to us that the amount of the Deloitte fee is not representative of the level of ongoing expense PSE might reasonably be expected to incur. The consulting assignment in this instance

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[205] PSE states that customers will continue to benefit from reduced taxes over the next twenty years if the Company's deductions are ultimately upheld. PSE Brief at 41 (citing Exh. No. 237C 17:20 – 18:2 (Story)).
[206] PSE Brief at 40.
[207] Exh. No. 421 at 11: 6-8 (Russell).
[208] Exh. No. 237C at 18: 2 (Story).

concerned a matter more complicated and contentious than what the Company might expect to encounter on a year in and year out basis.[209] We exercise our judgment on this issue by determining that one-third of the Deloitte fee, $270,732, is a reasonable amount to be included in rates. Our decision to spread the $812,196 amount over three years is consistent with, and in that sense informed by, our determinations concerning rate case expense, including consulting fees, as discussed below. If, in future proceedings, PSE can demonstrate through evidence of a pattern of expense that some greater amount is warranted, the Commission may adjust this expense. Here the evidence is sparse and will support no more than what we allow.

153 Turning to another point, Adjustment 2.11—Property Taxes is implicated here because PSE, in its rebuttal testimony, suggested that a reasonable solution to the parties' disputes over PSE's removal of the Montana tax refund in Adjustment 2.25 would be to offset the $1.9 million refund amount against PSE's inclusion of $3.8 million in back taxes paid to the Oregon tax authorities during the test year, as discussed further in connection with Adjustment 2.11. PSE proposes to recover the resulting amount over three years.[210] Staff, in its Initial Brief, states that it has no objection to this approach.[211]

154 We find reasonable the proposal to offset the $1.9 million Montana tax refund amount against the $3.8 million in back taxes paid to the Oregon tax authorities, with the resulting amount to be spread over three years and approve that treatment for purposes of setting rates in this proceeding. This decision will be reflected in our calculations of adjustments 2.11 Property Taxes and 2.25 Montana Corporate Tax.

155 The Commission finds that the impact of these decisions (*i.e.*, including incentive pay, and the matters discussed under "Deloitte Fee") coupled with the

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[209] See, e.g., TR. 777:13-779:13 (Story).
[210] Exh. No. 237C at 18: 13-21 (Story).
[211] Staff Initial Brief at 38, n.208.

uncontested portions Adjustment 2.10—Miscellaneous Operating Expense, results in a decrease in NOI of $967,242.

156 There is yet one additional dispute that we must resolve in this connection. The Company asks the Commission to pre-approve an adjustment to rates in the event that the Internal Revenue Service reverses the tax benefit of $72 million that both Staff and PSE have treated as a reduction to rate base. PSE also asks the Commission to include any IRS assessed interest that might result from such a disallowance.[212]

157 The Company states that the IRS is currently undertaking a review of all utilities that have taken this tax deduction and will not soon complete that review. The result is not predictable.[213] Staff argues that this means it is premature to grant PSE's request for pre-approval of an automatic rate adjustment that also includes IRS assessed interest.[214]

158 PSE argues that it is neither fair nor reasonable to include the benefits of this deduction (which is still contingent)[215] in current rates while reserving for a future ruling – and presumably a potential disallowance argument – what should be a straightforward statement of the Commission's commitment to permit recovery of these funds if the Company is ultimately required to pay them to the Federal government.[216]

159 We cannot lawfully prejudge future rates. However, we do find it appropriate to recognize in principle that if the IRS successfully challenges in court the adjustment PSE and other utilities have taken, and requires future repayment of the current benefits taken, presumably with interest, PSE should file an

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[212] Exh. No. 237C at 6:14 to 7: 1 (Story).
[213] *Id.* at 6:2-3 (Story); TR. 778:12 - 779:13 (Story).
[214] Staff Initial Brief at 45.
[215] Exh. No. 273C 5:19 – 7:1 (Story); TR. 777:13 – 779:9 (Story).
[216] PSE Reply Brief at 49.

accounting petition asking for appropriate treatment of any back taxes and interest assessed.

e. Adjustment 2.11—Property Taxes

160 We discussed in the preceding section how this matter will be resolved in connection with the treatment of the Montana Corporate tax adjustment and the Deloitte fee dispute. Here, for the sake of clarity, we provide brief additional discussion of the point in dispute. The contested component of the property tax adjustment concerns PSE's proposal to amortize a test period payment to the Oregon Department of Revenue for taxes related to the 3rd AC transmission line during the 1995 through 2001 tax years.[217] PSE states that the taxes were subject to litigation for several years and that the Company was not billed for these back taxes until late 2002. Following a settlement with the Oregon Department of Revenue, PSE paid 75% of the assessed tax amount in the test year. This is the amount the Company seeks to recover in rates.

161 Staff argues this test period tax payment should be disallowed because it is a one-time (*i.e.*, non-recurring) payment concerning a pre-test period liability. Staff argues that current Oregon taxes are pro formed into rates. Finally, Staff argues that disallowance is consistent with PSE's decision to remove a refund related to prior period Montana Corporate License Tax. Again, Staff notes that it has no objection to the proposal in PSE's rebuttal testimony[218] to net exclusion of the Montana tax benefit against the Oregon tax liability. As previously discussed, that is the solution we adopt for purposes of setting rates in this proceeding. Therefore we find PSE's adjustment appropriate.

162 The Commission finds that this adjustment increases NOI by $1,679,813.

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[217] PSE Brief at 41-42; Staff Brief at 38. There is an uncontested component to this adjustment: recalculation of property taxes with current levy rates rather than the estimated rates in the as-filed case.

[218] Staff Brief at 38, fn. 208 (citing Exh. No. 237C at 18:13-21 (Story)).

f. Adjustment 2.18—Rate Case Expense

i. General Rate Proceeding Cost Treatment and Amount

163 PSE argues that it should be allowed to defer and recover through amortization over three years its full rate case expense, as it has done in previous cases over the past 20 years.[219] PSE argues that its proposed treatment is appropriate because most such expenses are incurred after the test year, incurred on an irregular basis, and are highly variable. Finally, PSE argues that normalizing these costs will likely lead to contentious disputes in future cases.

164 Staff's rate case expense adjustment has two components designed to transition PSE away from its current practice of automatically deferring and amortizing all rate case costs. First, Staff amortized over three years, but without rate base treatment, both the remaining costs the Company deferred for its 2001 general rate case and the costs it has deferred through August 2004 for the current general rate case. Second, Staff included a normalized amount for both remaining 2004 rate case costs and one-half (*i.e.*, $650,000) the cost of the 2003 PCORC, all divided by three years, the period over which these costs were incurred.[220]

165 Staff argues that its proposal is consistent with the requirements of the FERC Uniform System of Accounts that rate case costs must be expensed through Account 928, Regulatory Commission Expense, unless the Commission expressly approves deferred accounting to Account 186, Miscellaneous Deferred Debits, which generally does not earn a return on the deferred balance.[221] Staff states that PSE deferred its rate case costs to Account 182.3, Other Regulatory Assets, which generally does earn a return on the deferred balance.[222]

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[219] PSE Initial Brief at 42.
[220] Staff Initial Brief at 39 (citing Exh. No. 421 at 22:17 - 23 (Russell); Exh. No. 423 at 20).
[221] *Id.* at 39-40 (citing Exh. No. 421 at 16:15 - 17:12 (Russell). Staff notes that the Commission has adopted the FERC Uniform System of Accounts through WAC 480-100-203).
[222] *Id.* (citing Exh. No. 421 at 19:13 - 20:2 (Russell)).

166 PSE states that it did not file for express authority to defer rate case costs, as it did for PCORC costs, because the Company "understood that it already had Commission authorization to defer general rate case costs."[223] Staff argues that the Commission has never expressly authorized PSE to defer rate case costs and treat them as a regulatory asset. Staff argues that in previous PSE proceedings the Commission has held that deferred accounting always requires express, advance approval. Staff quotes from the Commission's order on reconsideration in PSE's 1992-1993 general rate proceeding as follows:

> Deferred accounting was a recurring issue in the first stage of this case. Puget had set up several deferred accounts, and sought to recover certain expenses dollar for dollar. The Eleventh Supplemental Order makes it clear that advance Commission approval is necessary before deferring costs . . . . The Commission has authority to approve deferral; without such approval the company has no authority to defer.[224]

167 ICNU, like Staff, argues that the Commission should adopt a rate case expense adjustment in this proceeding that results in a reasonable amount of normalized rate case expense being included in rates. ICNU also argues, however, that the Commission should reject Staff's and PSE's respective proposals to allow the Company to defer and amortize all or part of the 2004 rate case expense.[225] ICNU provides considerable detail in its Initial Brief concerning the Commission's prior admonitions to PSE that the Company must not create deferral accounts and treat them as regulatory assets without first seeking and obtaining express authority from the Commission.[226] ICNU points out that the language quoted above from the order on reconsideration in PSE's 1992-1993 rate case is preceded by the following paragraph:

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[223] PSE Reply Brief at 43 (citing TR. 760:4-9 (Story)).
[224] *WUTC v. Puget Sound Power & Light Co.*, Docket Nos. UE-920433, *et al*., 20th Supplemental Order on Reconsideration and Clarification at 20 (1994).
[225] ICNU Initial Brief at 21.
[226] *Id.* at 24-26.

> In reviewing the issue of the recovery of costs of this proceeding, and recalling the numerous issues addressed in the Eleventh Supplemental Order regarding deferral of costs by Puget, the Commission has determined that it is appropriate now to make it clear to Puget that it may not defer any of the costs of this prudence proceeding. The Commission will look further at the costs when, and if, a request for recovery is made.

168 ICNU argues that the 20th Supplemental Order thus explicitly addressed PSE's practice of setting up a deferral to recover the costs of prosecuting cases before the Commission and made clear the Commission's view that deferral of such costs, like other costs, is improper absent express authority. Thus, ICNU argues, PSE was on notice that it must seek express authority to defer rate case expense, yet the Company did not do so in this, or the prior, general rate proceeding. ICNU argues on this basis that the Commission should reject Staff's proposal to allow PSE to defer the 2004-05 rate case expenses through August 2004 on the rationale that PSE may have legitimately misinterpreted prior Commission orders "to allow blanket authority to defer general rate case costs."[227]

169 Both ICNU and Staff argue that allowing PSE to defer rate case expense creates an incentive for the Company to spend excessively in preparing and presenting rate proceedings or, at least, provides no incentive to PSE to control its rate case expenses.[228] ICNU and Staff argue that the level of PSE's spending in recent cases impacts the ability of other parties having substantially lower litigation budgets to participate effectively in Commission proceedings. Staff argues that its proposal to normalize rate case expense moves toward leveling the field by motivating PSE to reduce its rate case expenses. Finally, Staff argues that its proposal ensures that the burden of proof remains "squarely and properly on the Company to justify a normal level of rate case expenses, as opposed to shifting

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[227] *Id.* at 26 (citing Exh. No. 421 at 21:1-6 (Russell)).
[228] *Id.* at 29; Staff Initial Brief at 41 - 42.

that burden to the Commission and Staff to find excessive or imprudent expenditures in multi-year deferrals."[229]

170 Despite the clear language in the Commission's prior orders, it seems that PSE has been slow to understand the longstanding principle that the Commission absolutely requires a company that wishes to book costs to a deferral account for treatment as a regulatory asset to first apply for and obtain express authority to do so. We reiterate, and reemphasize that principle here. We determine that PSE should be denied a return on the remaining balance in the rate case expense deferral account that it maintained, without express authority, to account for the costs of its 2001-2002 general rate proceeding and into which it booked expenses incurred in the present proceeding though August 2004. If PSE has booked any rate case expense to this deferral account since August 2004, we require that such amounts be removed. PSE will amortize the authorized balance over three years.

171 Given that the parties agreed to the recovery of a certain level of costs in their settlement of the 2001-2002 proceeding without bringing to the Commission's attention the improper accounting treatment PSE was giving these costs, it would be unfair to deny PSE any recovery of these costs, as ICNU urges. Moreover, again in light of the fact that neither Staff nor any other party expressly objected to PSE's ongoing deferral of rate case expense in 2001 and 2002, we cannot find that PSE had no basis whatsoever to infer that it might continue that practice in this proceeding. Thus, we will accept Staff's proposal that PSE be allowed to recover its costs incurred in this proceeding through August 2004 by amortization over three years, but without the addition of any return on those costs.

172 Going forward, PSE will recover the costs it incurs in prosecuting rate cases as a normalized expense. Based on PSE's updated estimate of expenses incurred in this rate proceeding, Staff argues we should authorize a total annual amount of $977,807 for rate case litigation. This includes the $216,666 amount Staff

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[229] Staff Initial Brief at 42.

advocates for PCORC expense, as discussed below. PSE's estimate of 2004 rate case costs is $3,054,844, according to PSE's Reply Brief.[230] PSE's rate case cost adjustments would recover $1,411,222 on an annual basis, including $650,000 for PCORC expense. PSE and Staff agree to the amount for general rate case expense, approximately $761,000.

173 ICNU is sharply critical of certain costs that PSE incurred in this proceeding, particularly costs for outside consultants.[231] Staff joins in these criticisms.[232] ICNU contends that "the Commission should drastically reduce the total costs incurred for Puget in this proceeding to reflect an appropriate normalized amount to be included in rates on an ongoing basis."[233] ICNU, however, makes no specific proposal regarding what amount is "appropriate." Although Public Counsel says that it supports ICNU on this issue, Public Counsel also does not make a specific proposal.[234] Indeed, no party makes any specific proposal for disallowance of all or some portion of PSE's rate case costs incurred in this proceeding.[235]

174 PSE argues that its costs in this proceeding are not excessive. PSE states in its Reply Brief that it incurred $5.34 million for its 2001 general rate case, $2.28 million more than it is requesting here.[236] Furthermore, PSE argues that it has managed to control its costs in this proceeding, noting that the $3 million in rate case costs the Company requests in this case are some $1.74 million less than the estimate filed in the Company's direct testimony in April 2004.[237]

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[230] *Id.* at 39, 43; PSE Reply Brief at 44.
[231] Staff Initial Brief at 32-34.
[232] *Id.* at 41-42; Staff Reply Brief at 14.
[233] ICNU Initial Brief at 35.
[234] Public Counsel Initial Brief at 49; Public Counsel Reply Brief at 11.
[235] NWIGU also support ICNU's positions, but offers no specific recommendation of costs that should be disallowed. NWIGU Initial Brief at 14-15
[236] PSE Reply Brief at 45 (citing Exh. No. 244 (Story)).
[237] *Id.* (citing Exh. No. 246C (Story)). PSE notes that as of December 10, 2004, the Company had actually paid $2,318,413 for rate case costs, generally representing services received through November 2004.

175 ICNU also argues that the Commission should order, as proposed by Mr. Schoenbeck, that the Company and customers share the rate case expenses included in rates on a 50/50 basis.[238] ICNU does not develop this argument on brief. PSE argues that to accept ICNU's sharing proposal would be arbitrary and unlawful.[239] ICNU does not respond to this assertion in its Reply Brief.

176 We find no basis in our record upon which to adjust the amount both PSE and Staff recommend be allowed for general rate case expense. Mr. Schoenbeck's sharing proposal is not grounded in statute. His proposal is not based on any expert analysis that would provide a factual basis for not allowing the Company to recover half of the costs it has, in fact, incurred. Accordingly, we will not adjust PSE's rate case expense as ICNU proposes.

ii. PCORC Cost Treatment and Amount

177 Although the parties agree that PCORC costs should be treated as a normalized expense in rates, there remains a significant dispute, and some degree of confusion, concerning the appropriate amount to be reflected in rates. PSE states that it incurred $1.3 million in legal and consulting expenses in it first PCORC.[240] Staff and ICNU witnesses filed testimony opposing PSE's requested recovery of the PCORC expense.[241]

178 PSE and ICNU both believed at the close of evidentiary proceedings that only two proposals were on the table. PSE and ICNU understood that there was an agreement between PSE and Staff that the Company's deferred accounting petition in Docket No. UE-031471 should be denied in favor of including $650,000 as a normalized level of PCORC costs in rates.[242] In fact, Staff's position is that one-third of that amount, or $216,666 should be included as normalized

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238 ICNU Initial Brief at 35-36 (citing Exh. No. 371HC at 29:4-6 (Schoenbeck)).
239 PSE Initial Brief at 44.
240 *Id.* at 58.
241 Exh. No. 421 at 18:1-15 (Russell); Exh. No. 371HC at 29:4 - 30:1 (Schoenbeck).
242 PSE Initial Brief at 58; ICNU Initial Brief at 37; PSE Reply Brief at 54; ICNU Reply Brief at 14-15.

rate case expense. Staff argues in its Reply Brief that there should have been no surprise in this regard because the exhibits accompanying Staff's direct testimony indicate clearly that the allowed PCORC costs and estimated 2004 rate case costs were "expensed over 3 years."[243]

179 In any event, by the time Initial Briefs were filed PSE correctly understood Staff's proposal to be that an amount of $216,666 would be included in rates for PCORC expense. ICNU's proposal is that the Commission should reduce the total amount of PCORC expense to $500,000 to reflect what ICNU regards to be normalized amount, and require the Company and customers to each bear an equal share of those costs.[244] In other words, the Commission would include $250,000 in rates for PCORC expenses under ICNU's proposal.

180 PSE argues that it should be allowed to include $650,000 in annual rates for PCORC expense. Staff argues that the Company's adjustment assumes that it will file a PCORC every year, which does not reflect experience.[245] Staff observes that in the three years since the PCORC mechanism was put in place PSE has filed only one case. Three year is the period of time that Staff used in its adjustment. PSE argues that the Company will be adding resources over the next several years and will likely be filing PCORCs on a regular basis.[246] Staff argues that if PSE makes more frequent PCORC filings in the future, the normalization period may be adjusted to reflect those new circumstances.[247]

181 PSE argues that Staff's adjustment would only allow cost recovery for one PCORC every six years, if costs remained at the level of the 2003 case, or every three years, if costs were half of that amount.[248] Staff responds that while the Company spent $1.3 million to litigate the 2003 PCORC, the case was very

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[243] Staff Reply Brief at 15 (citing Exh. No. 423 at 20, line 4 (Russell)).
[244] Exh. No. 371HC at 29:4 - 30:1 (Schoenbeck).
[245] Staff Reply Brief at 15.
[246] PSE Initial Brief at 58 (citing Exh. No. 61C 3:10 – 10:4 (Markell); TR.762:5 -24 (Story)).
[247] Staff Reply Brief at 16.
[248] PSE Initial Brief at 58.

controversial and required the Commission to make a prudence determination concerning PSE's Tenaska fuel gas acquisition.[249] Staff argues that PSE should not incur a similar level of expense for PCORC proceedings going forward. With reference to its full allowance for rate regulatory expense (*i.e.*, PCORC cases and general rate case), Staff states that PSE would recover almost $1 million every year for rate case litigation, whether the Company files a PCORC or a general rate case, or does not file any case at all.[250] Staff argues that this amount should be more than sufficient to cover PSE's litigation costs going forward.

182 ICNU, with reference to its proposal to include $250,000 in PCORC expense as a reasonable normalized amount, observes on Reply Brief that its proposal is approximately equivalent to the amount suggested by Staff.[251] ICNU argues that the Commission should adopt either the ICNU or Staff proposal.

183 We agree with ICNU and Staff that PCORC costs should be included in rates as a part of normalized rate regulatory expense. We reject ICNU's proposed level for PCORC expense for the same reasons we rejected its arguments concerning the level of general rate case expenses. It simply has insufficient support in the record. Moreover, ICNU is supportive of Staff's proposed level of expense.

184 Staff's position closely reflects PSE's experience thus far with PCORC proceedings. The Company may file more frequently in the future, but the evidence we have in this record supports the three year period that Staff uses to spread PCORC costs. The evidence also supports our finding that $650,000 is more representative of what this type of proceeding should cost than is the amount twice that high that PSE expended in its first proceeding, which was more expensive due to its novel and contentious nature.

185 The Commission finds that this adjustment increases NOI by $123,736.

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[249] *WUTC v. Puget Sound Energy, Inc.*, Docket No. UE-031725, Order No. 14 at ¶ 109 (May 2004).
[250] Staff Reply Brief at 16.
[251] ICNU Reply Brief at 15.

g. Adjustment 2.20—Property and Liability Insurance

186 Staff and the Company agree that test period and estimated insurance costs should be updated to actual.[252] PSE made certain adjustments through Ms. Luscier's rebuttal testimony.[253]

187 Staff argues in its Initial Brief that while PSE added costs for a new policy, the Company "excluded a refund related to the associated canceled policy."[254] PSE argues that the evidence Staff cites contradicts its claim because the Company included the refund in the amount of $4,389.[255] It appears from Ms. Luscier's testimony that PSE did include the refund associated with the cancelled policy.

188 PSE, in its rebuttal case, added $300,000 of costs related to a new policy. Staff points out that under the Commission's rules pro forma adjustments give effect for the test period to all known and measurable changes that are not offset by other factors.[256] Staff argues that the Company's adjustment violates this definition because the addition of a new insurance policy with new liability coverage may be offset by factors such as reduced risk or reduced levels of reserves for unanticipated events. PSE argues that there is no basis in the record for Staff's argument that the Company's addition of a new insurance policy "may be offset by factors such as reduced risk or reduced levels of reserves."[257]

189 PSE bears the burden to show that the proposed addition meets the definition of "known and measurable" and this requires consideration of potential offsets. PSE acknowledges that the record includes no evidence on this point.

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[252] Staff Brief at 43.
[253] Exh. No. 264 6:17-23 (Luscier).
[254] Staff Brief at 43.
[255] PSE Reply Brief at 47 (citing Exh. No. 264 6:21-22 (Luscier)).
[256] WAC 480-07-510(3)(b)(ii).
[257] Staff Brief at 43.

Accordingly, we find the $300,000 cost of the new policy is not known and measurable and should be removed from this adjustment.

190 The Commission finds that this adjustment decreases NOI by $232,606.

h. Adjustment 2.22—Wage Increase

191 Only one difference remains in dispute between Staff and PSE on this adjustment.[258] The Company disagrees with Staff's proposal to exclude wage increases for non-union employees in 2005. The Company states that it has included a 3% increase in its budget in every year since 1998 and is doing so for 2005.[259] Staff argues that the Company's position is not a proper pro forma adjustment since it is not known and measurable what amount, if any, will be awarded for 2005 until March of this year.[260] PSE responds that Staff's claim that the pro forma 3% wage increase is not known and measurable is incorrect. PSE states that while individual employees may receive differing percentage wage increases in approximately March of each year based upon performance reviews and calibration of performance to the overall merit pay budget, the Company's proposed overall 3% increase is consistent with its historic annual increases in non-union salaries, and is at the low end of industry standards.[261] PSE argues that providing the opportunity for performance-based increases is important if the Company is to attract strong talent, retain employees, and minimize the costs associated with turnover. PSE states that the Company's proposed 2005 increase for non-union employees is an important component of maintaining a competitive position within the industry and controlling its labor costs and should not be removed from the Company's requested rate relief.[262]

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[258] Staff argues in its Initial Brief that although PSE says it agrees with Staff's calculation of "slippage," the Company erred in its calculation. In its Reply Brief, the Company agrees that Staff's calculation of slippage is correct, rather than the Company's. PSE Reply Brief at 47.
[259] Exh. No. 333 at 8:1-3. (Hunt).
[260] Exh. No. 441at 14:13-17 (Parvinen); TR. 601:6-8 (Parvinen).
[261] PSE Initial Brief at 45-46; PSE Reply Brief at 48.
[262] Exh. No. 333 at 7:15 – 8:16 (Hunt); Exh. No. 237C at 29:12 (Story); Exh. No. 238C at 27 (Story).

192 The Commission finds persuasive PSE's arguments concerning the reasons it is appropriate to allow this adjustment in rates as the Company proposes. The amount of the proposed adjustment is sufficiently definite in light of long-standing practice and expectations going forward that it is appropriate for inclusion as a normalized expense. We accept Staff's slippage calculation, which is not in dispute. This results in a decrease to electric net operating income of $2,348,089.

i. Adjustment 2.23—Investment Plan

193 The amount of this adjustment depends on our decisions concerning the wage increase adjustment—Adjustment 2.23 on the electric side. The Commission finds that this adjustment decreases NOI by $98,366.

j. Adjustment 2.25—Montana Corporate Tax

194 This adjustment contains two elements. First, as presented by the parties, this adjustment depends on the calculation of pro forma interest in Adjustment 2.06-Tax Benefit of Proforma Interest. Second, as discussed earlier with regard to Adjustment 2.10 and Staff's proposal to remove the cost of the Deloitte study, and Adjustment 2.11-Property taxes, this adjustment removes a refund of the Montana Corporate Tax, which resulted from actions PSE took on the basis of the Deloitte Study. As discussed earlier, we have determined that the Company's alternative proposal to offset the Oregon property tax against this refund and to spread the cost over 3 years is reasonable. We recalculate this adjustment to agree with the determination of pro forma interest in Adjustment 2.06 and to include one-third of the $1,892,000 tax refund.[263]

195 The Commission finds that this adjustment decreases NOI by $866,281.

[263] Exh. No. 237C at 20.

k. Adjustment 2.30—Production Adjustment Effect

196 PSE and Staff agree that the production factor of 1.281%. The parties state that the only difference between them in this adjustment, an amount of approximately $10,000 in revenue requirement ($6,153 in NOI), is the result of other adjustments. This does not appear to be correct. There are five input lines in the calculation of this adjustment that differ between PSE and Staff. As to several of these, the differences do indeed arise because there are differences between the parties in the adjustments on which they depend. Others, however, are less clear.

197 Turning to property insurance and property taxes in Washington, for example, there are no adjustments that explain the difference between Staff and the Company. On property insurance, we find that Staff's response to Bench Request No. 1 supports the Company number. As to property tax, Staff's response to Bench Request No. 1 indicates the amount came from actual results. The Company's response shows that the amount came from the pro forma level of property tax adjustment plus the addition of Fredrickson. We find that PSE's number is correct.

198 Finally, on the payroll tax component, the difference between PSE and Staff is solely related to the calculation of Adjustment 2.22, wage increase. Both parties took the total pro forma level payroll taxes in this calculation times the portion of wages that are production related, 15.15%. However, neither party included the payroll taxes from the merit pay calculation in adjustment 2.10, even though they included an allocated portion of the merit pay. These payroll taxes should be reflected in this adjustment.[264]

199 The Commission finds that this adjustment increases NOI by $545,504.

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[264] The Commission notes that neither party included the payroll taxes from the merit pay calculation in adjustment 2.10, but we recognize that the per books taxes in Adjustment 2.22 may include them.

l. Rate Base, Deferred Taxes and Working Capital—Electric

200 The Company included deferred rate case costs in working capital. We discussed in connection with Adjustment No. 2.18 that PSE should not have been deferring and amortizing these costs as it has done for many years. Whatever the Company may have assumed in the past, the fact is unavoidable that PSE, despite repeated cautions, neither sought nor was granted express authority for such accounting treatment. We agree with Staff that these costs should be included as non-operating investment, which reduces working capital. PSE will be allowed to recover these costs via amortization over three years, as we discuss above, but will no longer be permitted to earn an equity return on these legal and consulting fee amounts.

201 Adjusting to remove deferred rate case costs, we find that PSE electric working capital is $13,679,148.[265]

2. Uncontested Adjustments--Electric

202 The Commission has reviewed the uncontested adjustments summarized in Tables Four and Five and finds them reasonable. These adjustments should be adopted for purposes of setting rates in this proceeding.

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[265] Although PSE and Staff do not differ on working capital other than as to the matter of deferred rate case expense, we note that in our examination of the record concerning this issue we have discovered a number of deficiencies in the presentations of both Staff and PSE. For example, the Commission cannot match certain investment calculations because of inconsistent use of account titles. Thus, we cannot determine all substantive differences in the two calculations. Total Capitalization is different by $15 million dollars between the gas and electric calculations even though the same capital structure is used for gas and electric. Total assets also differ but due to the different descriptions used by the parties it is impossible to determine the exact cause. Another problem is that the allocation of net assets over which working capital should be spread is inconsistent between the two working capital calculations with respect to the treatment of CWIP, it appears only electric CWIP is subtracted in the electric calculation and gas CWIP in the Gas calculation. We find that the record will not support the Commission modifying these calculations, nor do not require anything further from the parties in this proceeding as it appears there is no measurable impact to rates. We note examples of these errors here so that they can be avoided in future proceedings.

TABLE FOUR

Uncontested Restating and Pro Forma Adjustments – Electric

Adjustment Number	Adjustment Description	Adjustment Amount
2.01	Temperature Normalization	$ 4,374,555
2.02	General Revenues	116,919,193
2.05	Federal Income Taxes	(4,651,347)
2.07	Depreciation/Amortization	(97,252)
2.08	Conservation	26,189,031
2.09	Bad Debts	961,153
2.12	White River	(73,280)
2.13	Filing Fee	(143,538)
2.14	D&O Insurance	5,175
2.15	Montana Energy Tax	(107,925)
2.16	Interest on Customer Deposits	(151,631)
2.17	SFAS 133	555,963
2.19	Property Sales	(2,918,307)
2.21	Pension Plan	(5,565,312)
2.24	Employee Insurance	(825,326)
2.26	Storm Damage	366,405
2.25	Frederickson Plant	(2,684,243)
2.30	Low Income Amortization	3,801,853
	TOTAL	**$ 135,955,167**

TABLE FIVE

Electric Rate Base

Uncontested Adjustments	
2.07 Depreciation/Amortization	($74,810)
2.08 Conservation	(11,569,864)
2.10 Miscellaneous Operating Expenses	1,711,055
2.12 White River	19,837,623
2.27 Frederickson Plant	75,444,529
2.29 Regulatory Assets	(46,237,863)
2.30 Production Adjustment	(9,748,332)
Total Uncontested Adjustments	**$29,362,338**

3. Summary of Electric Revenue Requirements Determinations

203 We summarize the results of our electric revenue requirement determinations in Table Six.

TABLE SIX

Puget Sound Energy Calculation of Electric Revenue Requirement Docket No. UE-040641	
Rate Base Return Requirement	$2,544,670,041 x 8.40%
Operating Income Requirement Proforma Net Operating Income	= $213,752,283 - $178,621,452
Net Operating Income Deficiency Conversion Factor	= $35,130,831 0.6207738
Revenue Requirement Deficiency (see note)	**= $56,592,001**
NOTE: Deficiency is before allocation to wholesale. Tariff's filed in compliance with this Order must adjust revenue deficiency to account for allocation to wholesale.	

4. Contested Adjustments—Gas

a. Adjustment 2.01—Revenue & Purchased Gas Revenue

204 Gas Adjustment 2.01 normalizes and restates weather-sensitive gas sales that occurred during the test year to reflect what would have been sold had temperatures been "normal."[266] Staff drew its normal weather from the National Oceanic and Atmospheric Administration's (NOAA) 30-year (1971-2000) normal temperature calculation while PSE used a 20-year rolling average.

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[266] Exh. No. 451 40:13-18 (Mariam); Exh. No. 261 3:7-11 (Luscier).

205 Staff argues that use of NOAA's 30-year data is both simpler and more accurate than PSE's method. Staff states that NOAA applies a robust statistical analysis that removes the effects of abnormalities in temperature and non-weather-related factors such as missing data, errors in recording data, and changes in instrumentation and observation practices.[267] This ensures that external factors that impact temperature over time are considered and the data are representative.[268]

206 This issue is being considered in a weather normalization collaborative that was commenced as part of Docket No. UE-031725.[269] PSE argues that pending the outcome of that ongoing discussion, the Commission should continue to use the method it has approved in the past. Specifically, PSE uses a 20-year rolling average NOAA temperature data ending September 2003, less the highest and lowest years.[270] PSE states that it is receptive to new approaches but argues that Staff's proposal is premature and not sufficiently developed for adoption.[271]

207 PSE states that it is "concerned" about certain aspects of Staff's approach, but the Company does not dispute that Staff's approach is more statistically rigorous than taking a simple average of data, removing the high and low years without regard to whether these years should be excluded on statistical grounds. PSE does not actually demonstrate any anomalous results attributable to the fact that the latest available NOAA 30-year data stops just short of the test year while unadjusted 20-year NOAA data is available through September 2003.

208 We find on this point that Staff's proposal marks a step in the right direction, leading to a more rigorous and more accurate determination of one of the several

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[267] Staff Brief at 46 (citing Exh. No. 451 at 37:18 - 38:3 (Mariam)).
[268] Exh. No. 451 at 44:1-9 (Mariam).
[269] Exh. No. 284 13:9 – 14:4 (Heidell); *WUTC v. Puget Sound Energy, Inc.*, Cause No. UE-031725, Tenth Supplemental Order (Feb. 2004); TR. 594:17-20 (Heidell).
[270] Exh. No. 284 15:19-21 (Heidell); *WUTC v. Wash. Nat. Gas Co.,* Docket No. UG-920840, Fourth Supplemental Order at 17-18 (Sept. 1993).
[271] PSE Initial Brief at 49 (citing Exh. No. 284 17:8-11 (Heidell)).

statistically based adjustments typically made in regulatory ratemaking analyses. Staff's method should be adopted in this proceeding. The parties should continue to work toward a more refined methodology.

209 Unfortunately, our acceptance of Staff's weather normalization calculation does not fully resolve the calculation of pro forma revenue in this adjustment. Gas Adjustment 2.01 includes normalized and restated municipal tax revenue to reflect taxes on "normal" volumes of gas sales. It appears that both Staff and PSE made significant, though different, calculation errors in this area.

210 Although the parties do not challenge each other's calculations, we find on our analysis of the record, including responses to our Bench Requests, that their calculation errors are large enough to require correction. As detailed in Appendix C to this Order, these errors cause PSE and Staff to understate revenues by about $2 million and $1.6 million, respectively. The Commission finds that this adjustment increases NOI by $2,109,555.

b. Adjustment 2.03—Tax Benefit of Proforma Interest

211 This adjustment, which corresponds to Adjustment 2.06 on the electric side, is a tax benefit associated with the interest on debt used to support rate base and construction work in progress that has associated tax deductible interest. Both Staff and the Company employ a rate base method to calculate the tax benefit of pro forma interest. This adjustment depends entirely on our determinations in other parts of this Order of rate base and the weighted cost of debt to be applied to rate base.

212 The Commission finds that this adjustment decreases NOI by $5,511,630.

c. Adjustment 2.07—Miscellaneous Operating Expenses

i. Incentive/Merit Pay and Associated Payroll Taxes

213 We discussed the arguments concerning this adjustment in connection with Adjustment 2.10 on the electric side. Based on our determinations there, the Commission finds that this adjustment increases NOI by $248,295.

d. Adjustment 2.11—Property and Liability Insurance

214 The Commission's resolution of this matter is discussed in connection with Adjustment 2.20 on the electric side. We adopt that discussion and determination here by reference. The Commission finds that this adjustment decreases NOI by $81,039.

e. Adjustment 2.13—Wage Increase

215 We discuss this matter thoroughly in connection with the associated adjustment on the electric side, Adjustment 2.22. The Commission finds that this adjustment on the gas side decreases NOI by $1,218,086.

f. Adjustment 2.14—Investment Plan

216 The amount of this adjustment depends on our decisions concerning the wage increase adjustment—Adjustment 2.13 on the gas side. The Commission finds that this adjustment decreases NOI by $54,995.

g. Adjustment 2.17—Gas Water Heater and Conversion Burner Rental Program

217 This adjustment is a Staff proposal. PSE did not propose any adjustment in its initial filing. Staff proposes to remove all revenue, operating expense, and rate base associated with this 40 year old program in consideration of Staff's interpretation of certain language in the settlement agreement the Commission approved to resolve PSE's general rate proceedings in 2001-2002. In Docket No. UG-010571, the Commission approved a settlement that included the following language concerning this program:

> The Executing Parties agree that the Company shall not request an increase in the revenue requirement associated with the Gas Water Heater and Conversion Burner Rental Program until at least September 1, 2005. In the event that the Company requests general rate relief prior to this date, it shall compute the request for rate relief without inclusion of the revenues, operating expenses, or rate base related to rentals.

Staff argues that these two sentences impose separate restrictions on PSE so that even though the Company did not request an increase in revenue requirement associated with this program, it nevertheless is required to "compute the request for rate relief without inclusion of the revenues, operating expenses, or rate base related to rentals," because it filed for general rate relief prior to September 1, 2005. Staff proposes to eliminate $8,137,320 of operating revenues, to add back $606,509 of operating income and to reduce rate base by $31,312,542.[272]

218 PSE argues that Staff is taking the second sentence of paragraph 5 of the Water Heater Settlement out of context and ignoring the first sentence.[273] PSE states that Staff's interpretation implies that "the Company agreed to an automatic multi-million-dollar penalty if it requested a general rate increase prior to September 1, 2005 for reasons unrelated to the water heater program—a prohibition to which the Company would never have agreed."[274] PSE argues that the two sentences in paragraph 5 must be read together to mean that any request for a rate increase prior to September 1, 2005, could not be based on, or seek rate relief for, increased costs or decreased revenues associated with this program.

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[272] Exh. No. 443 at 18:3 (Parvinen); Exh. No. 441 at 16:7 – 17:3 (Parvinen).
[273] PSE Initial Brief at 52.
[274] *Id.*

219 PSE argues that the second sentence is a “penalty” provision:

> it makes sense that the penalty for violating the bar on filing for additional revenue requirement associated with the program is more draconian than the bar itself. Otherwise, the other parties might be concerned that the Company would include such an increase in its filing and hope that the other parties would overlook it, with removal of the additional requested amount the only consequence of being discovered. By contrast, a penalty that requires removal of essentially the entire program from the Company's rates would give the other parties confidence that the Company would not attempt to violate the settlement.[275]

220 PSE states that it has not requested an increase in the revenue requirement associated with its gas water heater and conversion burner rental program in this proceeding.[276] PSE says that, in fact, it has requested a decrease of $974,831 in revenue requirement related to the gas water heater and conversion burner rental program, not an increase. It would follow from this that the “penalty” provision does not apply, according to PSE’s argument.

221 The Water Heater Settlement resolved certain issues related to the Company's historic under-recovery of depreciation from rental customers through the implementation of two principles.[277] The Company agreed that it would not request an increase in the revenue requirement associated with the gas rental business until September 1, 2005. The Company also agreed to a minimum depreciation expense for rentals until September 1, 2005.[278] As discussed in joint testimony presented in support of the natural gas settlement in Docket No. UG-011571, in 2002:

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[275] PSE Reply Brief at 50. This seems to us a strained attempt to explain other parties’ subjective intentions at the time the settlement was drafted. PSE’s speculation concerning other parties’ subjective intent is not helpful.
[276] *Id.* at (citing Exh. No. 321 5:8-15 (Karzmar)).
[277] Exh. No. 321 at 2:15 – 3:6 (Karzmar).
[278] *Id.* at 4:22-23.

> The test year level of depreciation on rental property is to be maintained over the next three years. This treatment is anticipated to result in a decrease or elimination of the depreciation deficiency on rental property thus resulting in the rental revenues covering rental costs at the end of the three-year period contained in the stipulation during which Company is not allowed to request an increase in the revenue requirement associated with the existing gas water heater and conversion burner rental programs.[279]

222 Staff argues, with reference to this testimony:

> Thus, through additional depreciation, the rental program was to be self-funded by September 2005, so that no subsidy from ratepayers would be necessary after that date."[280] If the Company elected to file a general rate case before September 2005, then the subsidy provided by ratepayers would have to be eliminated. Staff's adjustment implements that expectation and public policy objective.[281]

223 Staff argues that if we do not accept its proposal to eliminate the water heater program revenues, operating expense, and rate base, we should order PSE to maintain the test year level of depreciation until the Company's next general rate case. Staff states that this will ensure that customers will not provide a greater recovery of depreciation expense than would otherwise be in place after September 1, 2005. This proposal apparently would result in a credit balance (*i.e.*, credit for customers) after about 2006 because at that point the $31 million in rate base will have been fully depreciated and customers will be paying about $8 million per year in depreciation for a rate base asset that no longer exists.

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[279] Exh. No. 323 at 4-5.
[280] Staff Reply Brief at 18.
[281] *Id.*

224 PSE objects to Staff's alternative proposal, arguing it has no basis in the record and would violate paragraph 6 of the settlement agreement the Commission approved in 2002.

225 The language we are asked to interpret is ambiguous but it is clear enough that the Commission's overall intent in adopting these provisions was to ensure that the water heater program would be self-supporting and not require a subsidy from non-participant ratepayers after September 1, 2005. Staff's alternative proposal appears to accomplish that goal, protecting both PSE and its customers.

226 We determine that we should accept Staff's alternative proposal, rejecting its proposed Adjustment 2.17 and the associated rate base adjustment, but requiring that the test year level of depreciation expense be continued until PSE's next general rate proceeding.[282] At that time, the issue may be reexamined. In terms of the present proceeding, the Commission finds that no adjustment is required.

h. Rate Base, Deferred Taxes and Working Capital—Gas

227 As on the electric side, PSE and Staff differ on starting rate base for gas because they differ on the question whether PSE's rate case expense from the Company's 2001-2002 rate proceeding in Docket Nos. UE-011570, *et al.*, should be included in restated actual working capital.[283] We resolved the issue in our discussion of this issue on the electric side. We find that PSE gas working capital is $1,345,790. Accordingly, we accept Staff's starting actual rate base, which is $621,134 lower than PSE's.

228 The more significant difference between PSE and Staff in terms of restated and pro formed rate base on the gas side is Staff's proposal to remove $31,312,542 in connection with the Company's gas water heater program, as discussed in the

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[282] If the Company finds it is appropriate to do so, it may elect to file for an accounting order concerning the treatment of these costs after September 1, 2005.
[283] *See, supra*, note 111.

preceding section. We determine on the basis of our prior discussion that Staff's proposed adjustment to remove the water heater program rate base should be rejected.

5. Uncontested Adjustments—Gas

229 The Commission has reviewed the uncontested adjustments summarized in Tables Seven and Eight and finds them reasonable. These adjustments should be adopted for purposes of setting natural gas rates in this proceeding.

TABLE SEVEN

Uncontested Restating and Pro Forma Adjustments -- Gas

Adjustment Number	Adjustment Description	Adjustment Amount
2.02	Federal Income Taxes	$ (1,221,100)
2.04	Depreciation/Amortization	(156,853)
2.05	Conservation	754,507
2.06	Bad Debts	563,835
2.08	Property Taxes	(819,519)
2.13	Filing Fee	(116,245)
2.14	Pension Plan	(3,111,507)
2.15	Employee Insurance	(461,431)
2.16	Low Income Amortization	1,792,203
	TOTAL	**$ (2,776,110)**

TABLE EIGHT

Gas Rate Base

Uncontested Adjustments	
2.04 Depreciation/Amortization	($120,656)
2.07 Miscellaneous Operating Expenses	3,267,546
Total Uncontested Adjustments	**$3,146,890**

6. Summary of Gas Revenue Requirements Determinations

230 We summarize the results of our gas revenue requirement determinations in Table Nine.

TABLE NINE Puget Sound Energy Calculation of Gas Revenue Requirement Docket No. UG-040640	
Rate Base Return Requirement	$1,067,682,555 x 8.40%
Operating Income Requirement Proforma Net Operating Income	= $89,685,335 - $74,006,760
Net Operating Income Deficiency Conversion Factor	= $15,678,575 0.5962063
Revenue Requirement Deficiency	**= $26,297,231**

7. Catastrophic Events Automatic Deferral Authority

231 PSE currently has blanket authority to defer costs resulting from a "catastrophic storm," which is defined as an event where more than 25% of PSE's electric customers are without power due to weather-related causes.[284] The costs of storms that meet the threshold are deferred and, when approved for recovery by the Commission, amortized for recovery over 3 years.[285]

232 Staff and the Company agree that the definition of catastrophic storm should be changed because the threshold of 25% of all customers without power does not recognize that plant in rural and less populated areas can be severely damaged by catastrophic storms at a cost of repair that equals similar efforts in an area of

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[284] Exh. No. 421 at 25:3-5 (Russell); Exh. No. 131C at 28:3-4 (McLain).
[285] Exh. No. 131C at 28:6-7 (McLain); *see also*, Exh. No. 131C at 28:10-12 (McLain); Exh. No. 233C at 2.26:19 (Story); Exh. No. 238C at 2.26:19 (Story).

high-density population.[286] Thus, Staff and PSE agree that the current definition of a catastrophic storm should be replaced by the Institute of Electrical and Electronic Engineers (IEEE) standard 1366-2003, modified to shorten the duration of a sustained interruption from 5 minutes to 1 minute.[287]

233 Staff and PSE also agree that a cumulative annual cost threshold for the electric system is an appropriate second trigger to determine if costs can be deferred without the Company first seeking additional authority from the Commission.[288] The parties disagree, however, on the specific amount of the trigger.

234 PSE also argues that the Commission should expand the Company's existing deferral authority to include non-storm events that may impact the electric infrastructure and to include catastrophic events that may impact the gas infrastructure. Staff opposes both proposed expansions of authority.

235 Staff proposes that the Company defer costs exceeding $5 million for the period March through December of 2005, and $7 million for the following two fiscal years.[289] This authority would be subject to Commission review after December 2007.[290] PSE proposes a cumulative threshold of $3.5 million for the partial calendar year 2005, and $5 million for each calendar year thereafter.[291] No specific Commission review is contemplated.

236 PSE argues that, under Staff's proposal, the Company would have deferred $3.8 million less in catastrophic storm costs under the *new* method over the past five years than under the *existing definition* for storm events.[292] PSE states that based on the Company's experience over the past five years, the $5 million

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[286] Exh. No. 471 at 9:13 to 10: 5 (Kilpatrick); Exh. No. 131C at 29:1-9 (McLain).
[287] TR. 588:25 to 589:5 (Kilpatrick); Exh. No. 139 at 3:8-14 (McLain). Exh. No. 471 at 10:12-14 (Kilpatrick); Exh. No. 472.
[288] Exh. No. 421 at 25:8-10 (Russell); Exh. No. 139 at 1-6 (McLain).
[289] Exh. No. 421 at 27:11 to 28:2 (Russell).
[290] *Id.* at 27:6-9.
[291] Exh. No. 139 at 4:11-14 (McLain).
[292] PSE Initial Brief at 56 (citing Exh. No. 139 at 4:20 – 5:8 (McLain); Exh. No. 141 (McLain)).

threshold would require the Company to absorb nearly a half million dollars annually in excess costs (as well as costs for electric events that do not meet the IEEE standard).[293]

237 Staff argues its proposed thresholds are fair and, in some instances, make the Company better off than existing practice. For example, Staff states that in fiscal year 1999 the Company incurred $9.3 million in storm damage, but did not defer any costs under the current mechanism. Given a $7 million cost threshold, PSE would have deferred $2.3 million, according to Staff.[294] Staff states that its proposed thresholds are based on the actual distribution of storm costs between 1998 and 2003, and on statistical analysis.[295]

238 Finally, Staff argues, its proposal properly balances the interests of the Company and ratepayers.[296] Under both Staff and Company proposals, $4.6 million for storm damage would be embedded in rates.[297] If the Company were to incur $1 million in storm damage in a calendar year, the Company would keep $3.6 million (*i.e.*, $4.6 million less $1 million). If, on the other hand, PSE incurred $8.2 million in storm damage, it would absorb $2.4 million (*i.e.*, $7 million less $4.6 million) and it also would defer $1.2 million (*i.e.*, $8.2 million less $7 million).

239 Staff argues that PSE's proposal would shift risk to ratepayers. Using the same example discussed above, Staff states that under PSE's proposal the Company would keep the same $3.6 million as under Staff's proposal if actual storm damage is $1 million, but PSE would be required to absorb only $400,000 (*i.e.*, $5 million less $4.6 million) if actual storm damage reached $8.2 million. The entire $3.2 million (*i.e.*, $8.2 million less $5 million) would be deferred under PSE's proposed threshold.

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[293] *Id.* (citing Exh. No. 139 at 5:9-13 (McLain); Exh. No. 141 (McLain)).
[294] Staff Initial Brief at 51-52.
[295] Staff Initial Brief at 52 (citing Exh. No. 472; Exh. No. 140; and Exh. No. 142).
[296] *Id.* (citing TR. 849: 8 to 850: 6 (Russell)).
[297] Exh. No. 423C at 28, line 11.

240 PSE's argument is that the point of its proposal to change the criteria for deferral of catastrophic storm costs was to make the Company better off by reducing its risk of having to absorb storm related costs in any given year.[298] Thus, PSE acknowledges Staff's point that the Company's proposal shifts risks to ratepayers.

241 We find that Staff's proposed thresholds are more reasonable than those proposed by PSE. Staff's thresholds represent a more appropriate balance of risks between the Company and its customers. We note in this regard that there is nothing to prevent PSE from seeking authority to defer costs incurred in connection with events in the future by filing a petition for an accounting order. We conclude that Staff's thresholds should be adopted for purposes of this proceeding.

242 The fact that PSE is free to file accounting petitions in appropriate circumstances also influences our decision to reject PSE's proposal to expand its authority to automatically defer costs related to non-storm events on the electric side and to the gas side of its business. As Staff points out, PSE is the only regulated utility with automatic authority to defer storm damage costs. All other companies expense these costs, unless they file an accounting petition for specific approval for deferral treatment.[299] There is no reason why PSE cannot do the same for damage to its gas system from any cause or to its electric system from causes that are not related to weather.[300] Finally, the expansion of blanket authority to defer costs associated with man-made events that cause serious impact to PSE's system would, as Staff notes, even include events in which Company negligence is a factor. That is not an acceptable situation.

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[298] PSE Reply Brief at 52 (citing Exh. No. 131C at 27:15-19, 28:14 – 30:21 (McLain); Exh. No. 139 at 2:5-8, 4:15 – 6:12 (McLain)).
[299] Exh. No. 421 at 26:2-7 (Russell).
[300] *Id.* at 26:14-16 (Russell).

243 We conclude that PSE's request to expand its authority to defer costs related to catastrophic storms on the electric side of its business to encompass non-storm events and events affecting gas infrastructure or operations should be denied.

244 The final issue in this connection concerns reporting requirements. Staff's original proposal included a 30-day deadline after an event for the Company to file a report of deferral.[301] PSE argues that a 30-day reporting period would not provide the Company adequate time to ensure the integrity of storm or other catastrophic event data recorded in its system.[302] PSE also states that to the extent a cost trigger is included in determining if an event qualifies for deferral, a 30-day time period would not be sufficient for all event related costs to be recorded in the Company's system. PSE argues that a reporting period of 90 days would be more appropriate.[303]

245 Staff, on brief, recommends a compromise whereby the Company would be required to notify the Commission by letter as soon as possible within 30 days of a weather-related event that PSE reasonably believes will qualify for deferral treatment. Staff proposes that PSE also would be required to file a more specific follow-up report as soon as possible, but no later than 90 days after the weather-related event.[304]

246 The Commission finds that Staff's proposal is reasonable. We determine that PSE should be required to file a letter with the Commission within 30 days of a weather-related event that PSE reasonably believes will qualify for deferral treatment and to file a more detailed report no later than 90 days after the weather-related event.

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301 *Id.* at 28:2-5 (Russell). Exh. No. 421 at 28:2-5 (Russell).
302 PSE Initial Brief at 57.
303 *Id.* (citing Exh. No. 139 at 7:17 – 8:2 (McLain)).
304 Staff Initial Brief at 54.

8. Rate Spread and Rate Design Settlement

247 PSE, Staff, and other parties that took an active interest in the rate spread and rate design issues submitted a proposed Settlement Agreement that they ask the Commission to approve and adopt to resolve all issues on rate spread and rate design.[305] The Settlement Agreement is supported by Joint Testimony addressing why the Agreement will result in rates that are just and reasonable, and consistent with established Commission policies.[306] Several parties filed briefs or statements in support. No one opposes the request that we accept the terms of the Settlement Agreement to resolve the issues it concerns.

248 We have reviewed the proposed settlement terms in light of the record developed on these issues through prefiled testimony and exhibits that were admitted by stipulation and have considered the parties' discussion of the issues on brief. We find that the settlement terms are reasonable and resolve the issues in a fashion that will lead to rates that are fair, just, reasonable and sufficient. We conclude that the Settlement Agreement, attached to this Order as Appendix D, and incorporated here by reference, should be approved and adopted.

D. PCORC Costs (Docket No. UE-031471)

249 Docket No. UE-031471 is a petition by PSE for authority to defer to Account 182.3, Other Regulatory Assets, the Company's 2003 PCORC costs arising from outside services (*i.e.*, legal and consulting) and to include the deferred costs in working capital in future rate proceedings.[307] Staff and the Company now propose to include as expense a normalized amount of PCORC costs, though they differ over the precise methodology for doing so and, hence, on the amount that should be included in rates. We resolve the parties' disputes concerning the

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[305] Exh. No. 1.
[306] Exh. No. 2.
[307] Exh. No. 425 (Russell).

amount of PCORC costs to be recovered in rates as a normalized expense earlier in this Order.

250 Given that no party now advocates deferral treatment for these costs, we conclude that the Company's petition in this Docket should be denied and the docket closed.

E. White River (Docket No. UE-032043)

251 In Docket No. UE-032043, PSE requested approval of certain accounting and ratemaking treatment of White River Hydroelectric plant and costs that were deferred during Federal Energy Regulatory Commission (FERC) proceedings on PSE's application for a license for the project.[308] PSE declined a FERC license because certain provisions of the federal agency's approval made the project uneconomic.[309] Thus, White River ceased operation on January 15, 2004.

252 Staff recommended that the following actions be taken to resolve the Company's Accounting Petition and to govern the ratemaking treatment of White River costs:

- Grant PSE's request to transfer the unrecovered plant costs associated with the White River Hydroelectric project to FERC Account 182.2, Unrecovered Plant and Regulatory Study Costs.

- Allow a return of, and on, the White River unrecovered plant costs in this proceeding and through the PCA, as variable cost items.

- Grant PSE's request to transfer the licensing charges, safety and other regulatory costs, and the costs to obtain water rights, to separate 182.3, Other Regulatory Assets, accounts in order to preserve their identity.

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[308] Exh. No. 424 at 5-42.
[309] Exh. No. 61C at 20:2-9 (Markell).

- Allow a return on these three 182.3 accounts in this proceeding and through the PCA as variable cost items.

- Deny PSE's request to begin amortization of these three accounts because the sale of White River is pending, but consider the application of proceeds from the sale and disposition of any remaining balances in a future proceeding.

- Book the proceeds from the sale of White River assets to a separate 182.3 account and treat the return on this credit balance account through the PCA as a variable cost item.[310]

253 The Company agrees with the Staff recommendations, which are reflected in Adjustment 2.12.[311] We find this uncontested proposal for resolving these issues reasonable. We conclude that the Commission should adopt the Staff's recommendations as set forth above. This determination is final with respect to Docket No. UE-032043.

FINDINGS OF FACT

254 Having discussed above all matters material to our decision, and having stated general findings and conclusions, the Commission now makes the following summary findings of fact. Those portions of the preceding discussion that include findings pertaining to the Commission's ultimate decisions are incorporated by this reference.

255 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates,

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[310] Exh. No. 421 at 13-15 (Russell).

[311] Exh. No. 237C at 8:8-17 (Story). The Company corrected a minor math error in its adjustment to which Staff has no objection.

rules, regulations, practices, and accounts of public service companies, including gas and electrical companies.

256 (2) Puget Sound Energy, Inc., (PSE) is a "public service company," a "gas company," and an "electrical company" as those terms are defined in RCW 80.04.010, and as those terms otherwise are used in Title 80 RCW. PSE is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

257 (3) The rates proposed by tariff revisions filed by PSE on April 5, 2004, and suspended by prior Commission order, have not been shown to be fair, just, or reasonable.

258 (4) The existing rates for electric service and gas service provided in Washington State by PSE have been shown to be insufficient to yield reasonable compensation for the services rendered.

259 (5) PSE's capital structure and costs of capital, which together produce an overall rate of return of 8.40%, are as set forth in the body of this Order in Table One.

260 (6) PSE's PCA mechanism power cost baseline requires adjustment consistent with the underlying and overall power cost determinations discussed in the body of this Order. Changes in the PCA mechanism that will occur on July 1, 2006, require that the PCA mechanism power cost baseline be reexamined in a subsequent proceeding to be commenced no later than February 28, 2006, so as to allow for timely implementation of any adjustment shown to be necessary for periods on and after July 1, 2006.

261 (7) The Commission's resolution of the disputed issues in this proceeding, coupled with its determination that certain uncontested adjustments are reasonable, results in our findings that PSE's natural gas revenue

deficiency is $26,297,231, and its electric revenue deficiency is $56,592,001. The electric revenue deficiency must be adjusted for allocation to wholesale.

262 (8) PSE requires relief with respect to the rates it charges for electric service and gas service provided in Washington State so that it can recover its natural gas service revenue deficiency and its electric service revenue deficiency.

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

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

CONCLUSIONS OF LAW

265 Having discussed above in detail all matters material to our decision, and having stated general findings and conclusions, the Commission now makes the following summary conclusions of law. Those portions of the preceding detailed discussion that state conclusions pertaining to the Commission's ultimate decisions are incorporated by this reference.

266 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings. *Title 80 RCW*.

267 (2) The rates proposed by tariff revisions filed by PSE on April 5, 2004, and suspended by prior Commission order, are not just, fair, or reasonable and should be rejected. *RCW 80.28.010.*

268 (3) PSE's existing rates for natural gas service and electric service provided in Washington State are insufficient to yield reasonable compensation for the service rendered. *RCW 80.28.010; RCW 80.28.020.*

269 (4) PSE requires relief with respect to the rates it charges for natural gas service and electric service provided in Washington State. *RCW 80.01.040; RCW 80.28.060.*

270 (5) The Commission must determine the fair, just, reasonable, and sufficient rates to be observed and in force under PSE's tariffs that govern its rates, terms, and conditions of service for providing natural gas and electricity to customers in Washington State. *RCW 80.28.020.*

271 (6) PSE should have the opportunity to earn an overall rate of return of 8.40% based on the capital structure and costs of capital set forth in the body of this Order, including a return on equity of 10.3% on an equity share of 43.00%.

272 (7) PSE should be authorized and required to make a compliance filing to recover its revenue deficiencies of $26,297,231 for natural gas service and $56,592,001 for electric service. The electric revenue deficiency must be adjusted for allocation to wholesale. *WAC 480-07-880(1).*

273 (8) PSE should reset its PCA mechanism power cost baseline consistent with the underlying and overall power cost determinations discussed in the body of this Order, subject to the condition that the Company will make a subsequent filing for review of the PCA mechanism power cost baseline established by this Order no later than February 28, 2006, so that the Commission may effect any adjustment to the power cost baseline shown to be necessary for periods on and after July 1, 2006. Such filing should be in the form of a PCORC, a general rate filing, or another form proposed to and accepted by the Commission as appropriate, considering circumstances then prevailing. *WAC 480-07-880(2).*

274 (9) The rates, terms, and conditions of service that result from this Order are fair, just, reasonable, and sufficient. *RCW 80.28.010; RCW 80.28.020.*

275 (10) The rates, terms, and conditions of service that result from this Order are neither unduly preferential nor discriminatory. *RCW 80.28.020.*

276 (11) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order. *WAC 480-07-170; WAC 480-07-880.*

277 (12) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order. *Title 80 RCW.*

ORDER

THE COMMISSION ORDERS THAT:

278 (1) The proposed tariff revisions PSE filed on April 5, 2004, which were suspended by prior Commission order, are rejected.

279 (2) PSE is authorized and required to file tariff sheets following the effective date of this Order that are necessary and sufficient to effectuate its terms. The required tariff sheets must be filed by February 25, 2005, and shall bear an effective date of March 4, 2005.

280 (3) PSE is authorized to reset its PCA mechanism power cost baseline consistent with the underlying and overall power cost determinations discussed in the body of this Order, subject to the condition that the

Company will make a subsequent filing for review of the PCA mechanism power cost baseline established by this Order no later than February 28, 2006, so that the Commission may effect any adjustment to the power cost baseline shown to be necessary for periods on and after July 1, 2006. Such filing is required to be in the form of a PCORC, a general rate filing, or another form proposed to and accepted by the Commission as appropriate, considering circumstances then prevailing.

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

282 (5) The Commission retains jurisdiction to effectuate the terms of this Order.

DATED at Olympia, Washington, and effective this 18th day of February 2005.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

RICHARD HEMSTAD, Commissioner

PATRICK J. OSHIE, Commissioner

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

APPENDIX A

Capital Structure and Cost of Capital Proposals

TABLE A-1: Established in Docket Nos. UE-011570 and UG-011571

Ln #	Item	Capital Structure	Embedded Cost	Rate of Return
1	Long-Term Debt	51.74%	7.54%	3.90%
2	Short-Term Debt	5.83%	4.63%	0.27%
3	Trust Preferred			
4	Preferred Stock	2.43%	7.78%	0.19%
5	Common Equity	40.00%	11.00%	4.40%
6	Total Capital	100.00%		**8.76%**

TABLE A-2: Proposed by PSE Witnesses Cicchetti and Gaines

1	Long-Term Debt	45.59%	6.88%	3.14%
2	Short-Term Debt	3.09%	4.81%	0.15%
3	Trust Preferred	6.28%	8.60%	0.54%
4	Preferred Stock	0.04%	8.51%	0.00%
5	Common Equity	45.00%	11.75%	5.29%
6	Total Capital	100.00%		**9.12%**

TABLE A-3: Proposed by Staff Witness Wilson

1	Long-Term Debt	48.59%	6.88%	3.34%
2	Short-Term Debt	3.21%	4.55%	.15%
3	Trust Preferred	6.32%	8.60%	.54%
4	Preferred Stock	0.04%	8.51%	.00%
5	Common Equity	41.84%	9.00%	3.77%
6	Total Capital	100.00%		**7.80%**

TABLE A-4: Proposed by Public Counsel Witness Hill

1	Long-Term Debt	48.86%	6.86%	3.35%
2	Short-Term Debt	4.36%	4.00%	0.17%
3	Trust Preferred	6.74%	8.60%	0.58%
4	Preferred Stock	0.05%	8.51%	0.00%
5	Common Equity	40.00%	9.75%	3.90%
6	Total Capital	100.00%		**8.01%**

APPENDIX B-1

Gas Revenue Requirements Summary

Puget Sound Energy
Calculation of Gas Revenue Requirement
Docket No. UG-040640

Rate Base	$1,067,682,555
Return Requirement	8.40%
Operating Income Requirement	$89,685,335
Proforma Net Operating Income	$74,006,760
Net Operating Income Deficiency	$15,678,575
Conversion Factor	0.5962063
Revenue Requirement Deficiency	$26,297,231

Puget Sound Energy
Commission's determination of Proforma Gas
Net Operating Income
UG-040640

		PSE	Staff	Commission
NOI Actual		$81,455,387	$81,455,387	$81,455,387
Uncontested Adjustments				
2.02	Federal Income Taxes	(1,221,100)	(1,221,100)	(1,221,100)
2.04	Depreciation /Amortization	(156,853)	(156,853)	(156,853)
2.05	Conservation	754,507	754,507	754,507
2.06	Bad Debts	563,835	563,835	563,835
2.08	Property Taxes	(819,519)	(819,519)	(819,519)
2.09	Filing Fee	(116,245)	(116,245)	(116,245)
2.12	Pension Plan	(3,111,507)	(3,111,507)	(3,111,507)
2.15	Employee Insurance	(461,431)	(461,431)	(461,431)
2.16	Low Income Amortization	1,792,203	1,792,203	1,792,203
Total Uncontested Adjustments		($2,776,110)	($2,776,110)	($2,776,110)
Contested Adjustments				
2.01	Revenue and Purchased Gas	($1,236,133)	1,110,277	$2,109,555
2.03	Tax Benefit of Proforma Interest	(6,007,908)	(5,700,092)	(5,511,630)
2.07	Miscellaneous Operating Expense	106,298	635,846	248,295
2.10	Rate Case Expense	(164,617)	(164,617)	(164,617)
2.11	Property and Liability Insurance	(122,465)	(81,039)	(81,039)
2.13	Wage Increase (revised in reply brief by company)	(1,218,086)	(982,842)	(1,218,086)
2.14	Investment Plan	(54,995)	(41,872)	(54,995)
2.17	Gas Water Heater Program	0	606,509	0
Total Contested Adjustments		($8,697,906)	($4,617,830)	($4,672,517)
Total Adjusted Net Operating Income		**$69,981,371**	**$74,061,447**	**$74,006,760**

Puget Sound Energy
Commission's Determination of Net Gas Rate Base
UG-040640

NOI Actual:	
Utility Plant in Service	$1,755,514,587
Accumulated Depreciation	(540,807,236)
Accumulated deferred Taxes - Liberalized	(134,342,956)
Depreciation and Other Liabilities	(17,174,520)
Allowance for Working Capital	1,345,790
Total Actual Rate Base	$1,064,535,665
Uncontested Adjustments	
2.04 Depreciation/Amortization	($120,656)
2.07 Miscellaneous Operating Expenses	3,267,546
Total Uncontested Adjustments	$3,146,890
Contested Adjustment	
2.17 Gas Water Heater Program	$0
Total adjustments	$3,146,890
Total Rate Base	**$1,067,682,555**

APPENDIX B-2

Commission
Electric Revenue Requirements Summary

Puget Sound Energy
Calculation of Electric Revenue Requirement
Docket No. UE-040641

Rate Base	$2,544,670,041
Return Requirement	8.40%
Operating Income Requirement	$213,752,283
Proforma Net Operating Income	$178,621,452
Net Operating Income Deficiency	$35,130,831
Conversion Factor	0.6207738
Revenue Requirement Deficiency (note)	$56,592,001

(note) Deficiency is before allocation to wholesale. Tariffs filed in compliance with Commission's Order must reflect revenue deficiency after allocation to wholesale.

Puget Sound Energy
Commission's determination of Pro Forma Electric Net Operating Income
UE-040641

		PSE	Staff	Commission
NOI Actual		$219,638,434	219,638,434	$219,638,434
Uncontested Adjustments				
2.01	Temperature Normalization	4,374,555	4,374,555	$4,374,555
2.02	General Revenues	116,919,193	116,919,193	116,919,193
2.05	Federal Income Taxes	(4,651,347)	(4,651,347)	(4,651,347)
2.07	Depreciation /Amortization	(97,252)	(97,252)	(97,252)
2.08	Conservation	26,189,031	26,189,031	26,189,031
2.09	Bad Debts	961,153	961,153	961,153
2.12	White River	(73,280)	(73,280)	(73,280)
2.13	Filing Fee	(143,538)	(143,538)	(143,538)
2.14	D&O Insurance	5,175	5,175	5,175
2.15	Montana Energy Tax	(107,925)	(107,925)	(107,925)
2.16	Interest on Customer Deposits	(151,631)	(151,631)	(151,631)
2.17	SFAS 133	555,963	555,963	555,963
2.19	Property Sales	(2,918,307)	(2,918,307)	(2,918,307)
2.21	Pension Plan	(5,565,312)	(5,565,312)	(5,565,312)
2.24	Employee Insurance	(825,326)	(825,326)	(825,326)
2.26	Storm Damage	366,405	366,405	366,405
2.27	Fredrickson Plant	(2,684,243)	(2,684,243)	(2,684,243)
2.28	Low Income Amortization	3,801,853	3,801,853	3,801,853
Total Uncontested Adjustments		$135,955,167	$135,955,167	$135,955,167
Contested Adjustments				
2.03	Power Costs	($58,730,987)	(63,315,425)	($53,032,522)
2.04	Sale for Resale	(113,651,741)	(95,699,399)	(113,651,741)
2.06	Tax Benefit of Proforma Interest	(9,337,425)	(7,530,496)	(8,124,355)
2.10	Miscellaneous Operating Expense	(1,573,174)	(98,086)	(967,242)
2.11	Property Taxes	1,679,813	2,510,356	1,679,813
2.18	Rate Case Expense	(157,991)	123,736	123,736
2.20	Property and Liability Insurance	(321,615)	(232,606)	(232,606)
2.22	Wage Increase (revised in reply brief by company)	(2,348,089)	(1,894,612)	(2,348,089)
2.23	Investment Plan	(98,366)	(74,901)	(98,366)
2.25	Montana Corporate tax	(1,283,057)	(1,272,865)	(866,281)
2.30	Production Adjustment	546,289	540,136	545,504
Total Contested Adjustments		($185,276,343)	($166,944,162)	($176,972,149)
Total Adjusted Net Operating Income		**$170,317,258**	**$188,649,439**	**$178,621,452**

Puget Sound Energy
Commission's determination of Net Electric Rate Base
UE-040641

NOI Actual:	
Utility Plant in Service	$2,578,449,579
Deferred Debits	334,433,269
Deferred taxes	(390,406,512)
Conservation Trust	11,569,864
Allowance for Working Capital	13,679,148
Other	(32,417,645)
Total Actual Rate Base	$2,515,307,703
Uncontested Adjustments	
2.07 Depreciation/Amortization	($74,810)
2.08 Conservation	(11,569,864)
2.10 Miscellaneous Operating Expenses	1,711,055
2.12 White River	19,837,623
2.27 Frederickson Plant	75,444,529
2.29 Regulatory Assets	(46,237,863)
2.30 Production Adjustment	(9,748,332)
Total Uncontested Adjustments	$29,362,338
Contested Adjustments	$0
Total Adjustments	$29,362,338
Total Adjusted Rate Base	**$2,544,670,041**

APPENDIX C

Explanation of Commission Adjustment To Municipal Tax Component of Adjustment 2.01-Revenue and Purchased Gas

Exhibit No. 265 (Luscier), page 2.01, line 7, shows PSE's calculation of municipal tax additions. Exhibit No. 443 (Parvinen), page 1, line 7, shows Staff's calculation of municipal tax additions. These revenue amounts, $26,426,999 and $27,271,843, respectively, are intended to recover municipal taxes on revenues collected in various cities in PSE's territory. The different amounts shown in the two exhibits are attributable in part to the fact that the parties used different calculation methods and both parties made errors in applying those methods.

In Bench Request No. 4, which we directed to PSE with reference to Exhibit No. 265, the Commission asked how the revenue amounts on line 7 were calculated and for a breakdown of the revenue sensitive taxes on line 24. In Bench Request No. 5 the Commission put the same questions to Staff with reference to Exhibit No. 443.

Staff's calculation of line 7 is the product of the municipal tax rate, 3.879%, and the $703 million amount shown for pro forma operating revenues on line 3. Staff subtracts the booked amount $21,271,843 from the restated amount $27,271,843 to determine the municipal tax adjustment of $5,646,846.

This application of the 3.879% is inconsistent with Staff's calculation of the conversion factor. Mr. Parvinen's conversion factor on page 19 of Exhibit No. 443 includes the municipal tax rate of 3.879%, but this tax rate is applied to all revenue including the municipal tax additions revenue in the calculation of total revenue deficiency as shown on page 21 of Exhibit No. 443.

Contrary to Staff's approach, the Company's response to Bench Request No. 4 and Mr. Heidell's Exhibit Nos. 306 and 307 indicate that the 3.879% municipal tax rate is the ratio of municipal tax revenue to total adjusted operating revenue including municipal tax revenue, rental revenues, and other miscellaneous revenues. PSE's Attachment A to the response to the Bench request uses a formula that incorporates this fact. However the factor used is not applied to the total operating revenue adjustments PSE pro formed in Adjustment 2.01.

Both responses indicate that the line 24 amount includes the municipal tax rate of 3.879% within the gross revenue tax rate of 7.91%. While this is an acceptable approach, we note it is different from what the parties did on the electric side, which was to remove this factor totally from revenue and expense.

When we separate municipal tax out of the total adjustments on line 24, we find that Staff increased the tax expense by the product of 3.879% and the total revenue adjustment of $187,091,126 on line 16, which equals $7,257,265. Thus, the increase in municipal tax *expense* in Staff's calculation is approximately $7.25 million. This is about $1.6 more than Staff's adjustment to Municipal tax *revenue* on line 7. The increase in expense, however, should match the increase in revenue.

Following a similar analysis of Exhibit No. 265, we see that PSE increases municipal tax expense by $6.8 million, yet the Company increases the municipal tax revenue by only $4.8 million. Thus, PSE understates municipal tax revenue by approximately $2 million. It appears from our review of PSE's response to Bench Request No. 4 Attachment A that PSE used the correct formula (*i.e.*, .03879/(1.0 – .03879) = .04036), but applied the resulting factor to a smaller revenue adjustment amount, approximately $119 million, as compared to the sum of the Company's revenue adjustments on lines 5, 9, and 13totalingapproximately $170.5 million.

The Commission's calculation of Adjustment 2.01, correcting for the errors described above, yields an increase to net operating income of $2,109,555.

Puget Sound Energy
Calculation of Adjustment 2.01
UE-040640

			Actual	Restated	Proformed	
Operating revenue			$522,553,139	$603,126,156	$703,005,746	
Revenue Adjustment Before Municipal and Other Operating Revenues						$180,452,607
Other Operating Revenues			11,020,477	11,664,675		
Adjustment to Other Operating Revenues						644,198
Miscellaneous Customer Charge Revenue Adjustment (staff line 13)						347,475
Total Revenue Adjustment pre Municipal Additions						$181,444,280
Municipal Additions	rate		3.87932%			7,322,882
	formula		(rate/(1-rate)*other revenue adjustments			
Total Revenue Adjustment						$188,767,162
Expenses:						
Purchased Gas -(Staff)						$169,899,443
Other Operating Expense	rate		0.003688357			696,241
Gross Receipts	rate		0.079071			14,926,008
Subset of gross receipt (Muni tax)	rate		3.87932%	7,322,882		
Total Expense Before FIT						$185,521,692
NOI before FIT						$3,245,470
FIT			0.35			1,135,915
Net NOI Adjustment						$2,109,555

APPENDIX D

Rate Spread and Rate Design Settlement Agreement