BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UG-040640 Docket No. UE-040641 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY, INC. For an Order Regarding the Accounting Treatment for Certain Costs of the Company's Power Cost Only Rate Filing.	Docket No. UE-031471 (*consolidated*)
In the Matter of the Petition of PUGET SOUND ENERGY, INC. For an Accounting Order Authorizing Deferral and Recovery of the Investment and Costs Related to the White River Hydroelectric Project.	Docket No. UE-032043 (*consolidated*)

INITIAL BRIEF OF PUGET SOUND ENERGY, INC.

JANUARY 18, 2005

[07771-0089/BA050150.006]

REDACTED VERSION

PUGET SOUND ENERGY, INC.

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I./II. SUMMARY / INTRODUCTION / GENERAL ARGUMENT

A. The Company's Proposal

1. Puget Sound Energy, Inc. (the "Company") respectfully requests that the Commission issue an order approving its request for general rate relief in an amount equal to an annual increase in electric revenue of $99.8 million and natural gas revenue of $46.2 million, which includes a request that the Commission authorize a rate of return on common equity of 11.75% and a capital structure containing 45% common equity.

2. Although the Company has made great strides in improving its financial condition since the settlement of its last general rate case, it falls short of where it needs to be. The Company 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 has taken aggressive steps to address these issues, but now needs continued regulatory support to achieve these critical goals.[1]

3. The overall rate increase sought by the Company is 7.1% for electric customers and 6.3% for natural gas customers. Even with the requested increase, customers' rates still would rank among the lowest in the nation. More importantly, by strengthening the Company's financial profile and enhancing its credit rating, the requested increase will help keep rates low over time and stabilize customers' future energy costs.[2]

4. It is undisputed that the Company is facing a critical need for investment in new energy resources and new electric and gas delivery infrastructure, in order to serve the needs of a

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

[2] Exh. No. 51 10:4-9 & 6:9-11 (Reynolds); Exh. No. 53 6:9-11 (Reynolds).

steadily growing customer base and to upgrade aging facilities. To meet these needs, the Company will be required to access very large sums of capital over the next several years.[3] If the Commission grants the Company's requested relief in this case, the Company anticipates that it will strengthen its corporate credit rating which, at "BBB-", is currently barely investment grade.[4] An improvement in the Company's corporate credit 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.[5] These anticipated benefits of an improved credit rating far outweigh the anticipated costs.[6]

B. Proposals of Staff, Public Counsel and ICNU

5. The positions taken by Staff and Public Counsel with respect to the Company's capital structure and cost of capital fail to recognize the significant resource acquisition and infrastructure investment challenges facing the Company. Staff and Public Counsel also ignore the extent to which the Company's energy risk management efforts are being hampered by the Company's current corporate credit rating. Neither Staff nor Public Counsel presented a policy witness in this case to speak to the overall impact of their proposals on the Company or its customers.[7]

6. Instead, the external experts retained by Staff and Public Counsel present mechanistic and

[3] *See* Exh. No. 61C 3:10 – 15:10 (Markell); Exh. No. 131C 10:15 – 25:12 (McLain).
[4] *See* Exh. No. 15:15 – 19:17 (Valdman); Exh. No. 154 11:1 – 13:14 (Valdman); Exh. No. 171C 8:1 – 20:13 (Gaines); Exh. No. 179C 5:2 – 16:11 (Gaines).
[5] *See* Exh. No. 51 8:3 – 12:8 (Reynolds); Exh. No. 61C 10:4 – 15:10 (Markell); Exh. No. 71 16:18 – 24:21 (Ryan); Exh. No. 82C 3:1 – 9:4 (Ryan); Exh. No. 84C 2:5 – 15:9 (Ryan).
[6] *See* Exh. No. 179C 16:12 – 28:15 (Gaines).
[7] *See* TR. 851:4 – 853:24 (Russell).

outdated calculations of financial theory formulas and urge the Commission to approve an authorized return on equity (ROE) that would be among the lowest in the nation. These experts do not deny that their proposals will utterly fail to strengthen the Company's financial position or flexibility.[8]

7. Staff and ICNU advance a number of proposed adjustments that, if accepted, would significantly understate costs the Company will incur to provide service to its customers during the rate year. This would prevent the Company from having a fair opportunity to actually earn its authorized rate of return and would further degrade the Company's financial health.

C. Legal Standards

8. The ultimate question in this matter is whether the rates and charges proposed by the Company are fair, just, reasonable, and sufficient.[9] In making these determinations, the Commission is bound by the statutory and constitutional mandate that a regulated utility is entitled to (i) reasonable and sufficient compensation for the service it provides[10] and (ii) the opportunity to earn "a rate of return sufficient to maintain its financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk."[11] As the public service company proposing the increase, the Company bears the burden of proving

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[8] In surrebuttal on the stand, Mr. Hill stated that he was "not concerned" that adoption of his proposal will result in a downgrade of the Company's corporate credit rating to non-investment grade, but acknowledged that his proposal would not support any increase in that credit rating. TR. 519:25 – 520:8 (Hill).

[9] RCW 80.28.020; *People's Org. for Wash. Energy Res. v. WUTC*, 104 Wn.2d 798, 808 (1985) ("*POWER*").

[10] *POWER*, 104 Wn.2d at 808; *Puget Sound Traction Light & Power Co. v. Pub. Serv. Comm'n*, 100 Wn. 329, 334 (1918); RCW 80.28.010(1).

[11] *WUTC v. Avista Corp.*, Cause Nos. UE-991606, *et al.*, Third Supp. Order at 89 (Sept. 2000) (citing *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310, 312 (1989)). *See also POWER*, 104 Wn.2d at 811 (stating that rates must "enable the Company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed. . . ."); *id.* at 813.

that the proposed increase is just and reasonable.[12]

9. Unless a utility is given the opportunity to earn a reasonable return on its investment and recover its costs, customers as well as investors are harmed:

> It is just as important in the eye of the law that the rates shall yield reasonable compensation as it is that they shall be just and reasonable and nondiscriminatory from the standpoint of the customer, because unless every rate does yield reasonable compensation, public service companies must resort to discrimination in order to live or must eventually be forced out of business. Every statutory element must be recognized in the fixing of rates, or the result will be to defeat the legislative purpose.[13]

The Washington Supreme Court has observed that when the Commission disallows an operating expense a utility has incurred to serve its customers:

> the shareholders of the utility must absorb the disallowed expenses, with a resulting reduction in the actual rate of return earned by them. This means that disallowance of an expense in a rate case has the very real effect, among others, of increasing the risks of investing in the utility.[14]

10. Only the Company's proposed rate increase meets the standards set forth above. No other party adequately addresses the financial improvement necessary to maintain the Company's financial integrity and attract capital on reasonable terms.

III. CAPITAL STRUCTURE AND COST OF CAPITAL

11. The Company proposes an overall rate of return of 9.12%.[15] This is based on a requested authorized capital structure consisting of 45.59% long-term debt, 3.09% short-term debt, 6.28% trust preferred stock, 0.04% preferred stock, and 45% common equity.[16] The Company has

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[12] RCW 80.04.130(2).
[13] *State ex rel. Puget Sound Power & Light Co. v. Dept. of Pub. Works*, 179 Wn. 461, 466 (1934).
[14] *POWER*, 104 Wn.2d at 811.
[15] Exh. No. 171C 3:7-9 & Table 1 (Gaines); Exh. No. 178C 1:17 (Gaines); Exh. No. 179C 3:Table 3 (Gaines); Exh. No. 181C 1:17 (Gaines).
[16] Exh. No. 179C 3:Table 3 (Gaines); Exh. No. 181C 1 (Gaines).

requested an authorized cost of common equity of 11.75%, which is at the low end of the range supported by the Company's evidence.[17]

A. Debt

1. Long-Term Debt

12. The parties agree that the Company's cost rate for long-term debt is 6.88%.[18] The capital structure ratios for long-term debt, however, vary among their proposals. The Company proposed a capital structure with 45.59% long-term debt.[19] This capital structure takes into account (i) the Company's proposed equity ratio of 45.0%; (ii) projected equity issuances during the rate year; and (iii) adjustments to the Company's capital structure to account for the impacts of non-regulated operations.[20]

13. Staff's proposal of 48.59% long-term debt is artificially high for two reasons. First, although Staff's proposal purports to be based on the average capital structure during the rate year, it includes one month not in the rate year (February 2005) and excludes one month from the rate year (February 2006). [redacted][21]

14. Second, Staff utilizes consolidated common equity of the Company that includes the equity of unregulated entities. In aggregate, the unregulated entities have negative common equity, thus the impact of Staff's approach is to reduce the regulated utility's common equity and

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[17] Exh. No. 201 49:6 – 50:17 (Cicchetti); Exh. No. 206C 84:2-7 (Cicchetti).

[18] Exh. No. 179C 3:Tables 1-3 (Gaines); Exh. No. 181C 1:9 (Gaines); Exh. No. 490 1:2 (Wilson); Exh. No. 368 1:4 (Hill); Exh. No. 180 2:4 (Gaines).

[19] Exh. No. 179C 3:Table 3 (Gaines); Exh. No. 181C 1:9 (Gaines).

[20] *See, e.g.*, Exh. No. 181C 1-2 (Gaines).

[21] [redacted]

increase its debt.[22] Staff's proposal is a departure from the Commission's historical approach of isolating the utility from the effect of unregulated activities.[23] Staff has presented no evidence or policy discussion in this case in support of changing that approach.

15. Public Counsel proposes that rates be set on a capital structure with 48.86% long-term debt, based on the Company's capitalization as of March 31, 2004.[24] Public Counsel's long-term debt ratio is artificially high because it does not reflect increases in the Company's equity ratio that will result from retained earnings, dividend reinvestments, or common stock issuances.[25]

16. As discussed in greater detail in Section III(D), below, common equity issuances will be critical to fund the Company's resource acquisitions and infrastructure investments as well as its effort to improve its financial strength. It is uncontested that even without equity issuances, the Company's long-term debt ratio will continue to decrease and its equity ratio increase throughout the rate year and beyond, through retained earnings and dividend reinvestments. Setting rates in this proceeding based on long-term debt and equity ratios that disregard or do not fully reflect the Company's increasing equity ratio would be counterproductive to the Company's efforts to improve its financial condition, improve its credit rating, and best meet its customers' energy needs.

2. Short-Term Debt

17. The Company proposes a short-term debt cost of 4.81%, with a short-term debt ratio of 3.09%.[26] Staff proposes a short-term debt cost of 4.55%, with a short-term debt ratio of 3.21%.[27]

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[22] Exh. No. 179C 32:15 – 33:9 (Gaines).
[23] Exh. No. 179C 33:10-20 (Gaines).
[24] Exh. No. 351 28:24 – 29:5 (Hill); Exh. No. 368 1:4 (Hill).
[25] Exh. No. 179C 32:7-13 (Gaines); *see, e.g.*, TR. 487:22 – 488:12 (Gaines).
[26] Exh. No. 179C 3:Table 3 (Gaines); Exh. No. 181C 1:7 (Gaines).

Public Counsel's proposes a short-term debt cost of 4.00%, with a short-term debt ratio of 4.36%.[28] 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%.[29]

18. The Commission should reject Public Counsel's proposed short-term debt cost of 4.0% because it is not based on *the Company's* short-term debt costs. Rather, Mr. Hill estimated what he believes a generic "reasonable" short-term debt cost should be.[30]

19. Mr. Hill also criticized the Company's use of its wholly-owned subsidiary, Rainier Receivables, Inc. Mr. Hill implied in his direct testimony that the facility is too expensive and that it may make it harder for the Commission's Staff to audit the Company's books.[31] In fact, the Company has fully disclosed and accounted for Rainier Receivables in this case.[32] Tellingly, Staff has not raised the concerns expressed by Mr. Hill about Staff's knowledge of or ability to audit and account for the facility for ratemaking or other purposes.

20. The Rainier Receivables subsidiary does not increase the Company's short-term debt cost.[33] It is a bankruptcy-remote facility that securitizes the Company's accounts receivable, which increases the rating of the facility and lowers the Company's short-term borrowing rates.[34] Mr. Hill conflates the borrowing rate with the cost rate. The cost rate reflects all commitment fee

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[27] Exh. No. 179C 3:Table 1 (Gaines); Exh. No. 490 1:1 (Wilson).

[28] Exh. No. 179C 3:Table 2 (Gaines); Exh. No. 368 1:5 (Hill).

[29] Exh. No. 179C 35:6-- 36:15 (Gaines); Exh. No. 179C 3:Tables 1-3 (Gaines); Exh. No. 490 1:1 (Wilson); Exh. No. 368 1:5 (Hill); TR. 402:3-7 (Gaines).

[30] Exh. 179C 35:17 – 36:15 and n. 20-23 (Gaines); Exh. 369 1 (Hill); Exh. 370 1 (Hill).

[31] *See, e.g.*, TR. 531:9 – 532:19 (Hill).

[32] Exh. No. 154 25:4-16 (Valdman); Exh. No. 171C 28:7-10 (Gaines); Exh. No. 178C 3-7 (Gaines); Exh. No. 179C 37:4 – 43:5 (Gaines); Exh. No. 181 3-7 (Gaines); Exh. No. 187 1-95 (Gaines).

[33] Exh. No. 179C 45:2-5 (Gaines) (explaining that the weighted average of the Rainier Receivables borrowing rate was 1.34% during calendar year 2003, which is lower than the Company's weighted average commercial paper borrowing rate of 1.87%).

[34] Exh. No. 179C 37:4-22 & 42:20 – 45:21 (Gaines); TR. 453:22 – 454:6 & 466:23 – 468:3 (Gaines).

and amortization of issuance costs for the facility, divided by the amount of short-term borrowings outstanding.[35] The amortizations of these fixed costs are analogous to the annual fee on a credit card.[36] The Company had a number of months in the recent past in which the small amount of short-term borrowings results in a higher cost rate for its short-term facilities as a whole than would otherwise have been the case had it had higher borrowings. But this is not a function of the structure of Rainier Receivables; rather, it is a consequence of spreading the fixed costs of the facility over the Company's temporary low use of its credit facilities.[37] Borrowings under this facility remain the Company's lowest cost source of short-term liquidity.[38]

21. Mr. Hill's allegations also ignore that, in the absence of Rainier Receivables, the Company would have needed some other, more-expensive facility to provide liquidity and financial flexibility for ongoing management of its cash flow and operations.[39]

B. Trust Preferred Stock

22. The Company, Staff and Public Counsel agree on the cost rate of 8.60% for trust preferred stock.[40] The differences in trust preferred capital structure are relatively minor[41] and flow from disagreements regarding the equity component of the Company's capital structure.

C. Preferred Stock

23. The parties' cost rate and capital structure for preferred stock are essentially undisputed,

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[35] Exh. No. 179C 45:6-21 (Gaines).
[36] TR. 453:10-19 & 457:10 – 460:2 (Gaines).
[37] TR. 483:5 – 486:14 (Gaines).
[38] Exh. No. 179C 45:2-5 (Gaines).
[39] TR. 441:25 – 442:9, 452:21 – 453:3 & 485:7 – 486:14 (Gaines).
[40] Exh. No. 179C 4:1-2 (Gaines); Exh. No. 179C 3:Tables 1-3 (Gaines); Exh. No. 181C 1:11 (Gaines); Exh. No. 490 1:3 (Wilson); Exh. No. 368 1:3 (Hill).
[41] The Company, Staff and Public Counsel propose trust preferred components of 6.28%, 6.32% and 6.74%, respectively. Exh. No. 179C 3:Tables 1-3 (Gaines); Exh. No. 181C 1:11 (Gaines); Exh. No. 490 1:3 (Wilson); Exh. No. 368 1:3 (Hill).

each with a computed weighted average cost of preferred stock of 0.00%.[42]

D. Common Equity

24. In order to serve its customers during the rate year and into the future, it is undisputed that the Company needs to (i) invest in new generation or purchased power agreements;[43] (ii) invest in electric and natural gas infrastructure;[44] and (iii) engage in risk management activities to reduce the Company's exposure to volatile fuel costs.[45] These efforts will require very large sums of capital and a financial position significantly stronger than the Company's current "BBB-" corporate credit rating,[46] which is just one notch above a non-investment grade credit rating. The Company is facing this need to attract additional capital at a time when it has consistently been unable to earn the rate of return that has been authorized by the Commission and when investors are already wary of the risks associated with the utility industry in general and the unique risks inherent in the Company's portfolio.[47]

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[42] Exh. No. 179C 4:1-2 (Gaines); Exh. No. 179C 3:Tables 1-3 (Gaines); Exh. No. 181C 1:13 (Gaines); Exh. No. 490 1:4 (Wilson); Exh. No. 368 1:2 (Hill).

[43] *See, e.g.*, Exh. Nos. 61C & 66C (Markell).

[44] *See, e.g.*, Exh. Nos. 131C & 139 (McLain).

[45] *See, e.g.*, Exh. Nos. 71 & 82C (Ryan).

[46] Exh. No. 51 8:3 – 10:13 (Reynolds); Exh. No. 53 5:15 – 6:13 (Reynolds); Exh. No. 151 4:10 – 8:2 (Valdman); Exh. No. 154 2:4 – 5:9 (Valdman). The credit rating that matters with respect to this case, and which was referenced in the Company's testimonies, is the corporate credit rating for Puget Sound Energy, Inc. (referred to in the testimonies and this brief as "the Company"), which has a Standard and Poor's ("S&P") corporate credit rating of BBB-. Exh. No. 54 3 (Reynolds); Exh. No. 71 18:6-9 (Ryan); Exh. No. 76C 1:47, 2:34 & 3:9 (Ryan); Exh. No. 151 2:8-9, 5:19-20 & 7:12-20 (Valdman); Exh. No. 171C 2:8, 8:8-11, 9:9-15 & 10:5-16 (Gaines). This is the credit rating that counterparties and lenders look to as a proxy for the Company's financial condition. TR. 227:4-8 & 228:4 – 230:11 (Valdman); TR. 474:25 – 475:7 (Gaines); TR. 523:20 – 524:1 (Hill); TR. 905:12-16 & 906:5 – 907:13 (Ryan). To the extent any of the Company's other credit ratings are relevant for particular debt issuances, these track the Company's corporate credit rating. Exh. No. 151 15:16 – 16:13 (Valdman); Exh. No. 171C 12:10 – 13:5 (Gaines); Exh. No. 175 60 & 83 (Gaines); Exh. No. 179c 21:1-6 (Gaines). Puget Sound Energy, Inc.'s parent corporation, the holding company Puget Energy, Inc., also has an S&P corporate credit rating of BBB-. Exh. No. 54 3 (Reynolds). Unlike Puget Sound Energy, Inc.'s credit rating, Puget Energy, Inc.'s credit rating is impacted to some extent by the performance of Puget Energy, Inc.'s subsidiary InfraStrux. However, the impact of InfraStrux is relatively minor because it represents such a small percentage of Puget Energy, Inc.'s holdings. TR. 137:21 – 138:3 (Reynolds); TR. 474:25 – 475:7, 483:18-22 & 488:19 – 489:25 (Gaines).

[47] Exh. No. 151 9:16 – 15:11 (Valdman); Exh. No. 154 17:1 – 24:16 (Valdman).

25. In light of these challenges, the Commission should authorize a capital structure for the Company that includes a 45% common equity ratio and a return on that equity of 11.75%.[48]

1. Common Equity Ratio

26. Selecting the appropriate capital structure involves a balancing of risk and cost:

> The Commission has in previous orders used actual, pro forma, or imputed capital structures in determining rate of return. . . . The Commission in the past has proceeded on a case-by-case basis in determining appropriate capital structure based on balancing considerations of safety and economy.[49]

The Commission has summarized its inquiry in this area as follows:

> To determine the overall authorized rate of return, the Commission must establish an appropriate capital structure for the company. This capital structure need not be the actual capital structure the company experienced during the test year.
>
> The Commission determines an appropriate balance of debt and equity within the capital structure on the bases of economy and safety. Because the composite cost of debt is generally less than that of equity, overall capital costs can be expected to decrease as a greater portion of the capital structure is composed of debt. The economy of lower capital cost must be balanced against the safety of the capital structure.
>
> The concept of "safety" refers to the fact that the company has no legal obligation to pay a return to the holders of common stock. In dire financial circumstances, a company can reduce or suspend the payment of dividends to the owners of common stock without the legal consequences that would flow from a failure to pay interest on debt. In return, holders of common equity generally demand a greater return than do lenders who have a claim on the company's earnings.[50]

27. The Company's requested capital structure comprised of 45% common equity reflects the

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[48] Exh. No. 171C 3:7-8 & Table 1 (Gaines); Exhibit No. 178C 1:15 (Gaines); Exhibit No. 179C 1:Table 3 (Gaines); Exh. No. 181C 1:15 (Gaines).

[49] *WUTC v. Pac. Power & Light Co.*, Cause No. U-83-33, Second Supp. Order at 8 (Feb. 1984).

[50] *WUTC v. Puget Sound Power & Light Co.*, Cause Nos. UE-920433, *et al.*, Eleventh Supp. Order at 25-26 (Sept. 1993).

appropriate balance of economy and safety in this case, 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.

28. The Company has a corporate credit rating of "BBB-", given its current capital structure and coverage ratios. As of December 31, 2003, the Company's debt-to-total capital ratio, including the imputed debt related to purchase power agreements fails to meet the S&P benchmark for a credit rating in the "BBB" range (BBB+, BBB and BBB-). Were the Commission to authorize the Company's requested capital structure, the combination of the equity ratio and ROE included in the Company's proposal would likely result in ratios that support a "BBB+" corporate credit rating.[51]

29. An increase in the Company's corporate credit rating is justified by safety and economy. It will provide an important and needed buffer against potential reduction to non-investment grade status.[52] While customers would pay a little more for the cost of a higher equity ratio, customers will pay less over the next several decades for debt costs associated with the Company's resource acquisitions and infrastructure investments.[53] An increase in the Company's corporate credit rating will also strengthen the Company's position in negotiating resource acquisitions on favorable terms,[54] and enable the Company to engage in more extensive risk management activities than are possible at this time, given the credit requirements and

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[51] Exh. No. 171 6:2-13 (Gaines).

[52] Exh. No. 151 16:9 – 17:15 (Valdman).

[53] Exh. No. 179C 19:12 – 20:13 (Gaines); TR. 207:14-17 (Valdman); Exh. No. 206C 11:1-15 (Cicchetti); TR. 259:20-23 (Cicchetti).

[54] Exh. No. 61C 13:3 – 15:9 (Markell); Exh. No. 151 5:17 – 6:9 (Valdman).

constraints associated with wholesale power and gas market transactions and hedges.[55] Taken together, the benefits to customers associated with improving the Company's corporate credit rating far outweigh the increased cost of the Company's requested 45% equity ratio.[56]

30. The appropriate test for capital structure is the balance between safety and economy, not the Company's actual test year or rate year capital structure. Even so, the Company projects it will attain an actual capital structure of at least 45% equity [redacted].[57] The requested capital structure is within the range of, and almost 4% less than, the average of capital structures approved by other public utility commissions between January 1, 2003, and June 30, 2004.[58]

31. Neither Staff nor Public Counsel questions the reasonableness of a 45.0% equity ratio *per se*, nor do they criticize the Company's plan to achieve that ratio.[59] However, their analyses of the benefits of increasing the Company's equity ratio ignore many important benefits and focus only on the anticipated savings related to incremental long-term bond issues.[60] Based on these narrow analyses, they erroneously conclude that the benefits do not outweigh the increased cost to customers of setting a 45.0% equity ratio.[61]

32. Staff proposes a capital structure with 41.84% common equity.[62] Their analysis uses an

[55] Exh. No. 71 13:18 – 14:3 & 20:7 – 23:2 (Ryan); Exh. No. 78HC 1-5 (Ryan); Exh. No. 82C 4:18 – 5:5 (Ryan); Exh. No. 85HC 1-6 (Ryan); Exh. No. 151 7:12 – 8:2, 17:16-22 & 18:17-19 (Valdman).

[56] Exh. No. 179C 16:12 – 28:15 (Gaines).

[57] [redacted]

[58] Exh. No. 182 3 (Gaines). *See also* Exh. No. 3 1 (for the gas and electric industries "the median common equity ratio in the near-term future for companies with investment-grade rated subsidiaries is in the range of 51 to 52 percent").

[59] Exh. No. 351 24:22-24 (Hill) ("[I]f, by the time of the next rate proceeding, the Company has achieved a common equity ratio of 45%, then it would be reasonable to consider it for ratemaking purposes."); Exh. No. 481 30:8-9 (Wilson) ("these percentages do not represent an unreasonable capital structure per se").

[60] Exh. No. 179C 18:8 – 19:7 (Gaines); Exh. No. 481 34:n.2 (Wilson); Exh. No. 351 23:15 – 24:6 (Hill).

[61] Exh. No. 481 34:4-13 (Wilson); Exh. No. 351 23:15-23 (Hill).

[62] Exh. No. 179C 3:Table 1 (Gaines); Exh. No. 481 35:1-16 (Wilson).

average of the monthly averages of the Company's projected capital structure that does not include all the months in the rate year, [redacted]. Their analysis also erroneously includes negative retained earnings of the Company's unregulated activities.[63] Public Counsel proposes a capital structure with 40% common equity, thereby advocating that the Commission exclude altogether from the Company's rates the costs of its increasing actual equity ratio.[64]

33. Staff's and Public Counsel's proposals for capital structure and return on common equity would erode the Company's financial condition and undermine the Company's ability to attract debt and equity capital to fund its resource acquisition and infrastructure needs as well as to gain the financial strength to further support risk management activities.[65] Furthermore, both proposals result in degraded credit ratios that could well result in a credit rating downgrade.[66] Both of their proposed capital structures fail to reduce the Company's debt leverage.[67] Worse, their respective proposals move the Company's theoretical pre-tax interest coverage below the bottom end of the S&P range for a "BBB" range rating to below investment grade levels, and the Company's actual ratios will be worse.[68]

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[63] Exh. No. 179C 31:12 – 32:6 (Gaines); Exh. No. 481 35:1-16 (Wilson); TR. 554C:7 – 555C:17 (Wilson).

[64] Exh. No. 351 28:24 – 29:3 (Hill).

[65] Exh. No. 179C 7:4-7 (Gaines). Indeed, Staff witness Dr. Wilson appears to have a fundamental lack of understanding of the credit risks and constraints that the Company is facing in the wholesale power and gas markets. *Compare* TR. 572:4 – 573:4 (Wilson) *with* Exh. No. 71 16:18 – 24:21 (Ryan) and TR. 902:16 – 906:22, 907:14 – 909:6 & 912:15 – 916:13 (Ryan).

[66] Exh. No. 179C 7:10-11 & 8:5-10 (Gaines).

[67] Exh. No. 179C (Gaines).

[68] Exh. No. 179C 9:2-11 (Gaines). Public Counsel erroneously asserts that its proposal affords the Company an opportunity to achieve a pre-tax interest coverage ratio of 2.46 times. Exh. No. 351 4:10-11 (Hill). This ignores the effects of the additional leverage the rating agencies impute related to the Company's purchased power contracts. Exh. No. 179C 10:2-9 (Gaines); *see also* Exh. No. 175 27; Exh. No. 175 27. The Standard & Poor's methodology results in approximately $428.2 million of imputed debt related to the Company's existing long-term purchased power obligations. When one includes the impact of imputed debt, Public Counsel's 2.46 times coverage ratio drops

2. Return on Common Equity

34. The Commission should approve the Company's proposed 11.75% ROE to provide it the opportunity to earn "a rate of return sufficient to maintain its financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk."[69]

35. Staff witness Dr. Wilson and Public Counsel witness Mr. Hill advocate reducing the Company's currently authorized ROE by 200 and 125 basis points, respectively. They argue that investors require only single-digit ROEs of the Company because short-term interest rates, such as 90-day Treasury bills, are at 40 year lows. This conclusion is incorrect.

36. In fact, the Company's approved ROE should be increased to 11.75%, not decreased. The investment community recognizes that the Company must invest in generation and infrastructure to serve customers and expects that the Commission will grant the Company rate relief that is supportive of such investments.[70] Investors also expect to be adequately compensated if they choose to entrust their capital to the Company, given the nature of its portfolio and revenue.

37. The Company's proposed ROE is within the range granted by other public utility commissions throughout the nation, and particularly among states that plan to keep traditional cost-of-service regulation.[71] In addition, three separate financial analyses support the Company's proposed cost of capital of 11.75%: (i) a discounted cash flow (DCF) analysis; (ii) a capital asset pricing model (CAPM) analysis; and (iii) a risk premium analysis. The primary cost of capital analysis (the DCF analysis) performed by the Company's external financial expert, Dr. Cicchetti,

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to 2.16 times, below the range for an investment grade credit rating. Exh. No. 179C 10:14-18 (Gaines).

69 *WUTC v. Avista Corp.*, Cause Nos. UE-991606, *et al.*, Third Supp. Order at 89 (Sept. 2000) (citing *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310, 312 (1989)).

70 Exh. No. 206C 1:19 – 2:3 & 53:10-14 (Cicchetti).

71 Exh. No. 201 48:17 – 49:3 (Cicchetti); Exh. No. 182 (Gaines).

suggested that the appropriate return on equity for the Company was 12.2%.[72] To check this result, Dr. Cicchetti used two other analyses (CAPM[73] and Risk Premium[74]), which validated his DCF result with results of 12% to almost 13%. Dr. Cicchetti's analysis took into account specific circumstances facing the Company, including its extensive resource acquisition, infrastructure investment, and risk management needs, as well as its place in the industry. By contrast, witnesses for Staff and Public Counsel presented generic cost of capital testimony that did not consider the Company's particular facts or circumstances.

a. Public Counsel Cites Inapplicable ROE Cases

38. The Commission should not impose a low ROE on the Company based on citations to orders for utilities that bear no resemblance to the Company. It matters to investors that the Company is a vertically-integrated gas and electric utility located in a state that is retaining traditional cost-of-service regulation.[75] Neither Dr. Wilson nor Mr. Hill adequately account for the fact that the Company must compete for capital in a national landscape that includes many other investment options. In particular, Mr. Hill errs in suggesting that investors do not distinguish between the Company and utilities whose risk and return profiles are significantly different than a traditional, vertically-integrated gas and electric utility.

39. This is especially apparent in Mr. Hill's citation to a number of recent opinions issued by other regulatory jurisdictions that "have set equity returns below 10% during 2003 and thus far in

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[72] Exh. No. 201 32:7 – 36:7 (Cicchetti); Exh. No. 204 1 (Cicchetti).
[73] Exh. No. 201 36:7 – 43:16 (Cicchetti); Exh. No. 205 1-47 (Cicchetti).
[74] Exh. No. 201 44:1 – 48:15 (Cicchetti).
[75] TR. 565:16 – 566:6 (Wilson) ("Investors look at a broad cross-section of utility companies. They do take into account . . . whether a utility is vertically integrated or it's not vertically integrated"); TR. 534:24-25 (Hill) ("I don't deny that different kinds of companies is a factor in the [investor's] decision.").

2004."[76] Mr. Hill admitted that he had not reviewed those decisions, even though he is advocating that this Commission impose a similarly low ROE on the Company.[77] Mr. Hill stated his rationale for citing to such decisions as follows:

> The point is that utilities generally have similar risk compared to other investments in the marketplace, and I'm merely showing the Commission, because I believe there's a real aversion by regulatory bodies to go below the double digit level, i.e., to single digits. I wanted to show the Commission that there have been some regulators in the country that have done that.[78]

A review of the orders Mr. Hill cites reveals that they do not support the proposition that risks faced by utilities are similar, they rest on facts much different than those facing the Company.

40. For example, Connecticut Light & Power Company's ROE was reduced in the cited case to 9.85% from the 10.3% ROE that had been established for the company in 1998.[79] However, since 1998, the company had "reduced its operating risk by divesting itself of generation."[80] The company had also "become a stronger company, financially, as evidenced through higher credit ratings and a stronger capital structure."[81] In 1998, Connecticut Light & Power Company was a fully-integrated electric utility with (i) a significant portfolio of generation facilities; (ii) a bond rating of BBB-; and (iii) a capital structure comprised of 33% equity. By the time of the cited case, Connecticut Light & Power Company had (i) divested itself of its generation and become a transmission and distribution company only; (ii) attained a bond rating of A-; and (iii) improved

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[76] Exh. No. 351 5:6-8 & fn. 1 (Hill).
[77] TR. 498:5-7 (Hill).
[78] TR. 497:22 – 498:4 (Hill).
[79] *Conn. Power & Light Co.*, Docket No. 03-07-02, Decision at 143 (Conn. Dep't. of Pub. Util. Control Dec. 17, 2003).
[80] *Id.* at 130.
[81] *Id.* at 129.

its capital structure to 51.1% equity.[82] Despite these significant factual differences, Mr. Hill proposes an ROE for the Company that is 10 basis points *lower* than the ROE established for Connecticut Power & Light Company.

41. Mr. Hill's citations also include orders involving Rockland Electric Company[83] and Jersey Central Power & Light Company[84] in New Jersey. New Jersey restructured its electric industry in 1999 pursuant to the Electric Discount and Energy Competition Act ("EDECA"),[85] which transformed these utilities into "wires" companies. "Wires" companies are poor comparisons to vertically-integrated utilities, as recognized by New Jersey Board of Public Utilities:

> The restructuring of the electric industry in New Jersey has transformed [Rockland Electric Company] into a "wires" company, subject to advantageous regulatory policies embedded in EDECA. Typically, vertically integrated electric companies are riskier than pure "wires" companies. Neither Mr. Rosenberg nor Mr. Rothchild fully factored this presumption into their models when selecting "comparable" companies.[86]

42. Mr. Hill erroneously asserts that the New York Public Service Commission granted the St. Lawrence Gas Company an ROE of 9.5%.[87] In fact, the ROE was "designed to achieve a return on equity . . . of approximately 9.8% in the First Rate Year"[88] on a capital structure comprised of 56.64% equity.[89] The order anticipated that the company would thereafter be in a position to actually earn even higher rates of return on equity, and approved a mechanism under

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[82] *Id.* at 143.
[83] *Rockland Elec. Co.*, 2003 N.J. PUC Lexis 259 (N.J. Bd. of Pub. Utils. July 21, 2003).
[84] *Jersey Cent. Power & Light Co.*, 2003 N.J. PUC Lexis 248 (N.J. Bd. of Pub. Utils. Aug. 1, 2003).
[85] N.J. Rev. Stat §§48:3-49, *et seq.*
[86] *Rockland Elec.*, 2004 N.J. PUC Lexis 78 at *141. Mr Hill acknowledges later in his testimony that "wires" companies "have less operational risk than fully-integrated electrics" and are not comparable to the Company. Exh. No. 351 32:9-17 (Hill).
[87] Exh. No. 351 5:6-8 & fn. 1 (Hill).
[88] *St. Lawrence Gas Co., Inc.*, 2003 NY PUC Lexis 427 at *34 (N.Y. Pub. Serv. Comm'n Aug. 4, 2003).
[89] *Id.* at *58, Schedule 9.

which the company and customers would share earnings above an ROE of 10.1%.[90]

43. Mr. Hill also cited a West Virginia-American Water Company order[91] as an example of a commission imposing an ROE of 7%, and defended that citation by stating that "although water companies are thought to generally have somewhat less risk than gas and electric companies, they are similar in risk."[92] The Public Service Commission of West Virginia, however, disagreed with that premise in the very decision cited by Mr. Hill:

> The Company used far riskier ventures in natural gas companies with returns substantially higher than the Water Group and claimed that the groups were comparable. But natural gas investment is far riskier and not comparable to water.[93]

One other decision cited by Mr. Hill involved a water company,[94] and over a third of the decisions cited involved telecommunications companies.[95] Such companies are not involved in the same industries as the Company and have no comparability with the Company other than the fact that they, too, are subject to rate regulation.

b. DCF Analysis

44. The Company's DCF analysis indicates that investors expect a 12.2% ROE for the

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[90] *Id.* at *34-35.

[91] *W. Va.-Am. Water Co.*, Case No. 03-0353-W-42T, Commission Order (W. Va. Pub. Serv. Comm'n Jan. 2, 2004).

[92] TR. 498:21– 499:23 (Hill).

[93] *W. Va.-Am. Water*, Commission Order at 19. Moreover, the ROE of 7% imposed on West Virginia-American Water Company in that proceeding (i) was significantly lower (156 basis points) than that company's cost of preferred stock (8.56%); (ii) was barely higher (27 basis points) than that company's cost of long-term debt (6.73%); and (iii) is currently being reviewed by the Supreme Court of Appeals of West Virginia in Docket No. 040258

[94] *Tenn.-Am. Water Co.*, Docket No. 03-00118, Final Order (Tenn. Regulatory Auth. June 25, 2004).

[95] *Crown Point Tel. Corp.*, 2003 N.Y. PUC LEXIS 474 (N.Y. Pub. Serv. Comm'n Aug. 27, 2003); *Chazy & Westport Tel. Corp.*, 2003 N.Y. PUC LEXIS 475 (N.Y. Pub. Serv. Comm'n Aug. 27, 2003); *Phillips County Tel. Co.*, 2003 Colo. PUC LEXIS 1428 (Colo. Pub. Utils. Comm'n Dec. 31, 2003); *Verizon N.H.*, Order No. 24,265, N.H. PUC Cause No. DT02-110 (N.H. Pub. Utils. Comm'n Jan. 16, 2004); *Kearsarge Tel. Co.*, Order No. 24,281, N.H PUC Cause No. DT01-221 (N.H. Pub. Utils. Comm'n Feb. 20, 2004).

Company, which supports the Company's recommendation of an 11.75% ROE.[96] The 12.2% DCF ROE for the Company is lower than ROEs for comparable companies that (i) are of comparable size to the Company, (ii) serve customers in state that have rejected restructuring, and (iii) provide electricity and natural gas services.[97]

45. The DCF model is based on shareholder values and expectations. It analyzes the two components of shareholders' future income: expected dividends and expected capital gains.[98] In short, return on equity equals the sum of expected yield and expected growth in the share price.[99] The yield component of the DCF model is not controversial in this proceeding, and all parties that submitted financial testimony used an average yield of 4.4% for their analyses.[100] The more challenging growth component[101] forms the basis of disagreement among the expert witnesses.

46. There is no published consensus value for the growth expectations investors hold.[102] In seeking an equity cost rate one must determine, on the basis of factual information, what the most reasonable estimate of growth expectations held by investors is at any point in time.[103] The Company's growth component utilized Puget Energy, Inc.'s average monthly growth in stock price over the test year, which yields a growth rate of 7.8%.[104]

47. Use of the Company's average monthly growth in stock price over the test year as a measure of the growth component is an appropriate method of estimating growth for the

[96] Exh. No. 201 32:7 – 36:7 (Cicchetti).
[97] Exh. No. 201 34:10 – 35:7 (Cicchetti).
[98] Exh. No. 201 32:9-11 (Cicchetti).
[99] Exh. No. 201 33:17 – 34:1 (Cicchetti).
[100] Exh. No. 201 34:Table 5 (Cicchetti); Exh. No. 484 1:4 (Wilson); Exh. No. 351 52:Table 2 (Hill).
[101] Exh. No. 481 10:7-8 (Wilson).
[102] Exh. No. 481 10:8-9 (Wilson).
[103] Exh. No. 481 10:9-12 (Wilson).
[104] Exh. No. 201 34:Table 5 (Cicchetti).

Company because "traditional" measures of the DCF growth component are inapplicable to the Company's facts. First, the Company's dividend growth over the past decade has been *negative* 5.9%.[105] Second, applications of DCF theory typically postulate the equivalence of cash, earnings, and dividend growth, which does not hold true for the Company because of the Company's negative dividend growth. Third, when the assumed growth equivalence does not hold, stock appreciation becomes more important than dividend yield.[106]

48. Dr. Wilson and Mr. Hill both criticize the use of growth in stock price as a determinant of the growth rate component for the DCF analysis as being too volatile.[107] Each presented an updated version of the Company's DCF analysis in an attempt to demonstrate that reliance upon the growth in stock price since the Company prefiled its direct testimony would lower the Company's expected ROE.[108] However, these updates are misleading because the Company sustained negative growth in its stock price for the months of May, June, and July of 2004, following the Commission's order in the PCORC proceeding, Docket No. UE-031471, imposing the Tenaska disallowance.[109] That disallowance resulted in a reduction to earnings per share of 28¢ after taxes,[110] in part because it reduced the Company's PCA deferral below the cumulative PCA cap of $40 million. The stock market responded predictably to this negative news, and the Company's stock price demonstrated negative growth.[111] Subsequent to the market's digestion of this disallowance, the Company's stock price has rebounded and is again showing positive

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[105] Exh. No. 206C 45:8-10 (Cicchetti); Exh. No. 484 1:4 (Wilson).
[106] Exh. No. 206C 45:11-18 (Cicchetti).
[107] Exh. No. 481 11:7-9 (Wilson); Exh. No. 351 48:16-22 (Hill).
[108] Exh. No. 481 12:DCF Chart (Wilson); Exh. No. 351 52:Table 2 (Hill).
[109] Exh. No. 206C 71:21 – 72:2 (Cicchetti).
[110] Exh. No. 206C 72:2-3 (Cicchetti).
[111] Exh. No. 206C 72:3-4 (Cicchetti).

growth. If the three months when the Company's stock price was negatively affected by the Tenaska disallowance are excluded from the analysis, the ROE expected by the Company's investors would be 11.6% for the updated periods.[112]

49. As stated above, the growth rate employed by Dr. Cicchetti attempts to address the infirmities associated with the "traditional" DCF growth components because such "traditional" metrics fail given the Company's particular facts. By contrast, Dr. Wilson applies a "traditional" DCF analysis based on dividend growth rather than growth in stock price, notwithstanding the Company's negative dividend growth. To perform his "traditional" DCF analysis, Dr. Wilson adopts the list of comparable companies utilized by Dr. Cicchetti.[113] However, Dr. Wilson makes a fundamental error in applying "traditional" DCF to Dr. Cicchetti's list of comparables because most of those companies also have negative or zero dividend growth: two of the utilities on Dr. Cicchetti's list have zero dividends[114] and five utilities (including the Company) have negative dividend growth rates.[115] Nonetheless, applying dividend growth rates reported by the Institutional Brokers' Estimate Service (IBES),[116] Dr. Wilson concludes that the average ROE for this group would be 7.77%.[117] If one were to adhere to DCF theory and perform his "traditional" DCF analysis using only the three utilities from Dr. Cicchetti's group that do not have negative dividend growth or zero dividend, the average ROE would be 150 basis points higher.[118]

50. Dr. Wilson also applies a different "fundamental" DCF analysis to Dr. Cicchetti's list of

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[112] Exh. No. 206C 72:4-8 (Cicchetti).
[113] TR. 566:19 – 567:6 (Wilson).
[114] Exh. No. 484 1:5, 7 (Wilson).
[115] Exh. No. 484 1:1, 4, 6, 10 & 12 (Wilson).
[116] Exh. No. 483 1 (Wilson). 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.
[117] Exh. No. 484 1 (Wilson).

comparable companies that increases his group's average ROE to 8.63%.[119] However, in this analysis, Dr. Wilson uses dividend growth rates projected by Valueline that are lower than the IBES growth rates he used in his "traditional" DCF analysis. 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%.[120]

51. In addition, 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. If one were to apply Dr. Wilson's "fundamental" DCF analysis and Valueline dividend growth rate projections only 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%.[121] 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%.[122]

52. Unlike Dr. Wilson, Mr. Hill does not use Dr. Cicchetti's list of comparable companies. Instead, Mr. Hill developed his own list of "comparable" companies, from which he excluded any companies with negative growth rates.[123] Mr. Hill's elimination of companies with negative growth rates recognizes that "traditional" measures of the DCF analysis are inapplicable to the Company's facts because of Puget Energy, Inc.'s negative dividend growth. Removal of such

[118] Exh. No. 206C 46:3-14 (Cicchetti).
[119] Exh. No. 481 16:5 – 17:12 (Wilson); Exh. No. 485 1 (Wilson).
[120] Exh. No. 206C 47:13-15 (Cicchetti).
[121] Exh. No. 206C 47:16-18 (Cicchetti).
[122] Exh. No. 206C 47:18-20 (Cicchetti).
[123] Exh. No. 351 32:7-9 (Hill). Mr. Hill does reveal in footnote 11 of the same page that Puget Energy, Inc. – which he includes in his sample group – is the one exception to such exclusion.

companies means "traditional" DCF analysis can be applied to the group, but the resulting ROE is meaningless because the companies in the sample group used by Mr. Hill are not comparable to Puget Energy, Inc.

53. Moreover, Mr. Hill erroneously asserts that the thirteen electric and combination electric/gas utilities in his sample group

> had a continuous financial history and had at least 50% of operating revenues generated by electric utility operations. In addition, I eliminated companies that were in the process of merging or being acquired <u>and</u> had realized an upward stock price shift due to that activity or companies that had recently cut or omitted dividends. Also, the companies in the selected sample had to have a bond rating ranging from "BBB-" to "BBB+", generation assets, and a stable book value.[124]

In fact, several of the thirteen "comparable" companies used by Mr. Hill do not meet the screen described above. Great Plains Energy has only 48% of its revenue derived from electricity sales, below the 50% threshold. Pinnacle West Capital has an "A-" bond rating, which is above the "BBB-" to "BBB+" range listed. As noted above, Puget Energy, Inc. recently cut its dividend. In addition, only one of the utilities used by Mr. Hill (Central Vermont) has the same corporate credit rating as the Company ("BBB-").[125]

54. Companies that in fact met Mr. Hill's screen are not comparable to the Company for a number of reasons beyond the absence of negative dividend growth. First, several of the companies are much larger than the Company. For example, Energy East, Progress Energy and Entergy have more than twice the number of customers of the Company. First Energy's customer base is three times larger than the Company's.[126]

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[124] Exh. No. 351 32:9-17 (Hill).
[125] Exh. No. 358 1:9-13 (Hill).
[126] Exh. No. 206C 33:6-10 (Cicchetti).

55. Second, the Company has lower cash flow and higher capital spending per share than the other companies in Mr. Hill's sample group of companies. Going forward, the Company plans to increase its capital expenditures significantly as it acquires generation resources to meet its deficit power position, thereby creating even greater differences between it and the other companies in Mr. Hill's sample group. The Company also has fixed charge coverage of only about 75% of the average fixed charge coverage of these companies.[127]

56. Third, the Company's current debt capitalization is 59.0%, whereas the average for Mr. Hill's sample group at the utility subsidiary level is about 48.0%.[128] Only one of Mr. Hill's sample group utilities (Hawaiian Electric) has a higher debt capitalization than the Company. The Company is a definite outlier among "BBB-" to "BBB+" range rated utilities and risks a downgrade if it continues to invest without sufficient rate relief.[129]

57. Fourth, the Company purchases a large share of the energy it delivers to its customers. In 2003, the Company purchased 73% of its electricity needs. In contrast, Mr. Hill's sample group of "BBB-" to "BBB+" range rated utilities purchased on average only about 55% of their power needs.[130]

58. Fifth, half of the sample group companies listed by Mr. Hill are located in states where restructuring is active (Energy East, First Energy, Cinergy, Entergy and PNM) or has been pursued (Pinnacle West in Arizona).[131] Utilities located in states that eschew traditional regulation in favor of restructuring have average authorized returns on equity at least 110 basis

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[127] Exh. No. 206C 6:15 – 7:1 (Cicchetti).
[128] Exh. No. 206C 7:5-6 & 8:Table 3 (Cicchetti).
[129] Exh. No. 206C 7:7-10 (Cicchetti).
[130] Exh. No. 206C 9:1-5 (Cicchetti).
[131] Exh. No. 206C 33:17-21 (Cicchetti).

points lower than those, like the Company, located in states with traditional regulation.[132] Mr. Hill failed to recognize this important distinction.

59. Mr. Hill further claims that the Company is a lower investment risk than others by citing to the Company's price-to-earnings (P/E) ratio of 16.3[133] and comparing it to the average P/E ratio for Mr. Hill's sample group of 14.85 and the average P/E ratio in the electric industry of 14.5.[134] Because the Company's P/E ratio is higher than Mr. Hill's sample group or the industry average, Mr. Hill erroneously asserts that "Puget can be considered to have lower investment risk . . . ."[135] Mr. Hill's assertion is misleading because the Company's earnings (the E in the P/E ratio) have been low due, in part, to the recent Tenaska disallowance.[136] Such reductions to the earnings denominator make the Company a higher, not lower, risk investment.

c. CAPM Analysis

60. Dr. Cicchetti also performed a CAPM analysis as a check on his DCF analysis.[137] Under a CAPM analysis, the ROE for a company equals the sum of the risk-free rate plus (i) the company's beta multiplied by (ii) the amount by which the market return exceeds the risk-free rate (the "market premium").[138] A CAPM analysis requires judgment in determining the appropriate beta, risk-free rate and market return.

61. Dr. Cicchetti determined a beta for the Company of 0.62807 by analyzing its performance

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[132] Exh. No. 201 27:1 – 32:7 (Cicchetti).
[133] Exh. No. 351 33:15-17 (Hill).
[134] Exh. No. 351 33:11-14 (Hill).
[135] Exh. No. 351 33:16-17 (Hill).
[136] Exh. No. 206C 72:2-3 (Cicchetti).
[137] Exh. No. 206C 70:22 (Cicchetti).
[138] Exh. No. 201 36:7 – 37:17 (Cicchetti); Exh. No. 355 1 (Hill).

using quarterly data over the past three years.[139] For the risk-free rate, Dr. Cicchetti used the thirty-year Treasury bond yield of 4.89%, which matches most utility investment time horizons.[140] Dr. Cicchetti's market return consisted of an annualized average return for the Dow Jones Industrial Average since 1993 of 17.8%.[141] Using such inputs, Dr. Cicchetti's CAPM analysis produced a return on equity for the Company of 12.998%:

$$ROE(PSE) = 4.89\% + .62807(17.8\% - 4.89\%) = 12.998\%^{142}$$

Thus, Dr. Cicchetti's CAPM analysis shows that an ROE of almost 13% would be appropriate.[143]

62. Dr. Wilson also performed a CAPM analysis for the Company, but his analysis yielded an ROE of 7.48%, only 58 basis points higher than the Company's long-term debt costs.[144] This low return resulted from Dr. Wilson's startling use of a 90-day Treasury bill to represent the risk-free rate.[145] Use of the 90-day Treasury bill fails to match the investment horizon of utility equity and, as recognized by Mr. Hill, provides a resulting ROE too low to be meaningful.[146] As Dr. Cicchetti pointed out, simply substituting the thirty-year Treasury bond for the 90-day Treasury bill in Dr. Wilson's CAPM formula provides an ROE for the Company of 11.275%.[147]

63. Mr. Hill also performed a CAPM analysis that resulted in four widely-varying ROEs for the Company: 6.49%, 7.93%, 8.94% and 10.15%.[148] Mr. Hill's CAPM results of 6.49% and 7.93% can be summarily rejected because they use the 90-day Treasury bill for the risk-free rate

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[139] Exh. No. 201 38:3-6 (Cicchetti).
[140] Exh. No. 201 38:18 – 39:1 (Cicchetti).
[141] Exh. No. 201 39:18-20 (Cicchetti).
[142] Exh. No. 201 40:12-15 (Cicchetti).
[143] Exh. No. 201 40:16-18 (Cicchetti).
[144] Exh. No. 481 22:5 (Wilson).
[145] Exh. No. 481 20:2 (Wilson).
[146] Exh. No. 355 4 (Hill); Exh. No. 154 9:14 – 10:9 (Valdman); TR. 204:24 – 209:10 (Valdman); Exh. No. 206C 65:12-22 (Cicchetti).
[147] Exh. No. 206C 66:4-7 (Cicchetti).

component.[149] Mr. Hill recognizes that these ROEs are too low to be meaningful.[150]

64. Mr. Hill's CAPM results of 8.94% and 10.15% were correctly based on a 30-year Treasury bond rate rather than a 90-day Treasury bill rate for the risk-free rate component. However, he used market premiums that are too low. Mr. Hill's market premiums of 6.6% and 5.0% represent the arithmetic average and geometric average, respectively, of Ibbotson's published average risk premiums between stocks and long-term treasuries over the 1926-2003 time period.[151] Mr. Hill's market premium of 5.0%, which produced his 8.94% ROE, must be rejected because his use of a geometric average in this context is fundamentally incorrect.[152]

65. In addition, both the 8.94% and 10.15% ROEs produced by Mr. Hill's CAPM analysis utilize 77-year old financial market data, going back to 1926.[153] In doing so, Mr. Hill cites in his general comments, yet ignores in his CAPM analysis, recent evidence regarding risk-free rates and market premiums.[154]

d. Risk Premium

66. Dr. Cicchetti's third, and final, cost of equity analysis employed the risk premium methodology, which consists of the sum of (i) a risk-free interest rate, (ii) a corporate debt risk premium and (iii) a component to reflect equity risk.[155] Dr. Cicchetti used a thirty-year Treasury bond yield to represent the risk-free interest rate.[156] Dr. Cicchetti presented evidence that recent breakthroughs in financial understanding suggest that the risk spread varies inversely with

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[148] Exh. No. 363 1:1 (Hill).
[149] Exh. No. 355 4, 6 (Hill).
[150] Exh. No. 355 4 (Hill).
[151] Exh. No. 355 5 (Hill).
[152] Exh. No. 206C 56:14-17 & 63:18-20 (Cicchetti).
[153] Exh. No. 355 5 (Hill).
[154] Exh. No. 351 11:28-29 (Hill); Exh. No. 206C 65:3-6 (Cicchetti).

changes in interest rates on risk-free government bonds. Thus, current financial thought suggests that the traditional rough estimate of risk premiums of between 6% and 7% is inapplicable given the current market environment.[157]

67. Moreover, Dr. Cicchetti cited papers written by Professors Harris and Marston[158] that show that consumer confidence and market volatility also affect the spread in risk between stocks and long-term government bonds. Specifically, declines in consumer confidence, lower interest rates, and greater financial market volatility increase the risk premium spread. These factors suggest an increased spread, in today's markets, in equity risk relative to the long-term interest on federal bonds. Accordingly, Dr. Cicchetti adopted the risk premium spread of between 7.14% and 7.54% suggested by Professors Harris and Marston to account for current market conditions.[159] Using these risk premium estimates, Dr. Cicchetti developed a range of ROEs for the Company under the risk premium method of 12.03% and 12.43%.[160]

e. Market-to-Book Ratios

68. Both Dr. Wilson and Mr. Hill discuss at length the fact that the Company's market-to-book ratio of 1.28 is above 1.0 in arguing that the Company's return on equity should be slashed by 125 basis points or more.[161] Mr. Hill, for example, contends that "when market prices are

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[155] Exh. No. 201 44:4-6 (Cicchetti).

[156] Exh. No. 201 45:8-9 (Cicchetti).

[157] Exh. No. 201 44:15-20 (Cicchetti).

[158] Harris, Robert S. and Felicia C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts; Practical Issues in Valuations," *Financial Management*, Volume 21, No. 2, page 63 (June 22, 1992). Harris, Robert S. and Felicia C. Marston, "Risk and Return: A Revisit Using Unexpected Returns," *The Financial Review*, Vol. 28, No. 1, pp. 117-137 (Feb. 1993). Harris, Robert S. and Felicia C. Marston, "The Market Risk Premium Expectational Estimates Using Analysts' Forecasts," University of Virginia, Darden Graduate School of Business, Working Paper No. 99-08.

[159] Exh. No. 201 45:1-11 (Cicchetti).

[160] Exh. No. 201 45:13-14 (Cicchetti).

[161] Exh. No. 481 23:2 – 26:13 (Wilson); Exh. No. 351 40:9-12 (Hill); Exh. No. 366 1 (Hill).

above book value, investors expect utilities to earn equity returns that are greater than the market based cost of equity capital for those companies."[162] The Company's Chief Financial Officer, Mr. Valdman, pointed out that it his experience that investors do not use market-to-book ratios in making utility sector investment decisions.[163] There are many reasons why investors pay more than book value for a utility stock.[164] For example, market-to-book ratios in the utility industry are affected by the broader stock market market-to-book ratio, which are currently generally greater than one.[165] In this environment, it would be extraordinarily damaging to set an ROE for the Company that is based upon moving market-to-book rates toward 1.0.

69. In addition, underearning of authorized return suppresses the Company's share price, which explains why the Company's market-to-book ratio is low relative to the utilities in Mr. Hill's sample group (1.28 versus 1.45).[166] The Company does not currently earn its approved return on equity of 11.0%.[167] In fact, Mr. Hill puts the Company's actual return on equity at 7.7%, 7.2%, 7.0% and 7.5% for calendar years 2001, 2002, 2003 and 2004, respectively.[168]

70. This assertion is grounded on the false assumption that investors in utility stock expect to earn only what the utility earns on book value.[169] Investors' return expectations, however, are based on what investors expect to earn on their new investments, not the utility's original rate base.

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[162] Exh. No. 351 13:30-32 (Hill).
[163] Exh. No. 154 13:15 – 14:20 (Valdman).
[164] Exh. No. 206C 20:4-6 (Cicchetti).
[165] Exh. No. 206C 20:17 – 21:9 (Cicchetti).
[166] Exh. No. 206C 19:11-14 (Cicchetti).
[167] Exh. No. 206C 19:11 (Cicchetti).
[168] Exh. No. 359 5 (Hill).
[169] Exh. No. 206C 19:20 – 20:1 (Cicchetti); Exh. No. 154 13:15 – 14:20 (Valdman).

3. Conclusion on Common Equity

71. The average weighted costs of common equity approved by public utility commissions between January 1, 2003, and June 30, 2004, was 5.33%.[170] The Company's current weighted cost of common equity is 4.40% (the product of 11.0% ROE and 40.0% equity) and it proposes to move to a weighted cost of common equity of 5.29% (the product of 11.75% ROE and 45.0% equity).[171] Staff's proposal would dramatically reduce the Company's weighted cost of common equity to 3.77% (the product of 9.0% ROE and 41.84% equity),[172] and Public Counsel's proposal would reduce the Company's weighted cost of common equity to 3.90% (the product of 9.75% ROE and 40.0% equity).[173] The proposals of Staff and Public Counsel are out of sync with the equity ratios and returns on equity on which rates are being set across the nation.[174] More importantly, their proposals would significantly weaken the Company's financial position and undermine its efforts to acquire new resources, maintain and replace its aging infrastructure, and undertake additional wholesale market risk management activities on behalf of its customers. An approved capital structure with 45% common equity reflects an appropriate balance of safety and economy for the Company, and an authorized ROE of at least 11.75% is necessary to provide the Company the opportunity to earn a rate of return sufficient to maintain its financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk.

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[170] Exh. No. 182 3 (Gaines).
[171] Exh. No. 179 6:6-9 (Gaines).
[172] Exh. No. 179C 3:Table 1 (Gaines); Exh. No. 490 1:5 (Wilson).
[173] Exh. No. 179C 3:Table 2 (Gaines); Exh. No. 368 1:1 (Hill).
[174] Exh. No. 179C (Gaines).

E. Total Capital

72. The Commission should approve the Company's proposed overall rate of return on rate base of 9.12%, as detailed in Appendix A to this brief.

IV. REVENUE REQUIREMENT

A. Contested Adjustments—Electric[175]

1. Adjustment 2.03—Power Costs

73. Power costs should be determined in this proceeding based on projections that are as close as possible to costs the Company will actually incur to provide power to its customers during the rate year. The Commission should reject arguments that propose rate year power costs without regard to whether the Company is actually likely to be able to obtain or generate power at such average costs during the rate year.

74. The Company's approach is consistent with the PCA mechanism and sound principles of ratemaking. The PCA was intended to be a balanced mechanism, under which there was an equal chance for under recovery or over recovery of future, expected power costs.[176] When rates are set using projections of future power costs that are biased or do not reflect the best information available at the time rates are set, the mechanism becomes unbalanced and fails to provide an equal likelihood that the Company's actual power costs will be higher or lower than the costs recovered in rates. If rates are set using underestimated costs, this increases the likelihood that the Company's shareholders would be forced to absorb these "excess" power costs

[175] Appendix C lists the contested electric adjustments and associated differences in net operating income (NOI) and rate base, as well as a list of the electric adjustments PSE understands are uncontested.

[176] Exh. No. 82C 9:19-20 (Ryan); Exh. No. 237C 14:16 – 15:4 (Story); TR. 749:22 – 750:3 (Story).

the Company has incurred to provide power to its customers.[177]

75. The PCA's $40 million four-year cumulative cap should not be relied upon as a reason to set power costs artificially low. The cap results in a deferral of 99% of excess power costs after the Company has under-recovered $40 million of power costs; it does not provide immediate recovery of such excess costs in rates.[178] Thus, it puts the burden on the Company to bear the cash flow costs and risks associated with those deferrals.[179] Cash flow is a significant concern to the Company.[180] Moreover, investors may view costs recorded in the PCA deferral as contingent and subject to disallowance in annual PCA true-up filings.[181] In addition, the $40 million cap is set to expire on June 30, 2006, shortly after the end of the rate year.[182]

76. If power costs are set too low, it also sends the wrong price signals to customers and results in a different set of customers paying the costs of power consumed by customers today.[183] The Commission has recognized the importance of such considerations:

> PGA rates, *as price signals*, should provide *the most accurate estimate of expected gas costs and should be based on the Company's most accurate estimate of prospective gas costs*, with deferral accounting and true-up of revenues collected to actual costs.[184]

a. Gas Costs

77. In its initial filing, the Company projected the anticipated cost of gas during the rate year

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[177] Exh. No. 82C 10:1-6 (Ryan).
[178] *See WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-011570, *et al.*, Twelfth Supp. Order, Exhibit A to Settlement Stipulation ("PCA Settlement") at ¶¶ 2, 3.
[179] Exh. No. 82C 10:6-7 (Ryan).
[180] Exh. No. 154 3:15 – 4:6, 14:13-17, 20:20 – 21:5, 22:19-13 & 24:12-16 (Valdman); TR. 223:12 – 224:1 & 236:14 – 237: 21 (Valdman); Exh. No. 206C 5:22 – 7:4, 21:2-9 & 22:3-16 (Cicchetti); TR. 308:9 – 311:6 & 319:18 – 321:9 (Cicchetti).
[181] TR. 331:21 – 334:1 (Cicchetti).
[182] PCA Settlement at 2, ¶ 3.
[183] Exh. No. 82C 10:7-11 (Ryan); Exh. No. 451 32:7-11 (Mariam).
[184] *In the Matter of Purchased Gas Adjustment Mechanisms*, Cause No. UG-970001, Policy Statement at 2

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.[185] This methodology produced an average forward price for the rate year of $4.39/MMBtu for the Sumas market hub.[186]

78. Staff proposed that rate year prices be set using an average of the three-month rolling averages of forward NYMEX gas strip prices over the five months between December 2003 and April 2004.[187] Staff seeks to eliminate any period after April 30, 2004 from establishing gas costs during the rate year because such prices are, in the Staff's opinion, "biased."[188] However, analysis of the relationship between NYMEX forward market prices and spot market closing prices over the 1991 through 2004 historical period shows that there is no statistical reason these recent months should be excluded.[189] In addition, the recent data that Staff excluded is more informative of what prices are likely to be during the rate year.[190] At hearing, Dr. Mariam admitted that Staff's recommendation is based not on statistical analysis, but rather on an attempt to find a compromise between the lower forward prices that prevailed at the time the Company filed its original case and the higher prices that have developed since that time.[191]

79. The Company concurs with Staff's use of a three-month rather than 10-day average of NYMEX forward gas price strips, but disagrees with Staff's use of time periods that are now almost a year old and Staff's exclusion of more recent months of pricing data. On rebuttal, the

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(May 1997) (emphasis added).
[185] Exh. No. 71 25:15-17 (Ryan).
[186] Exh. No. 82C 21:14 (Ryan).
[187] Exh. No. 451 30:13-15 (Mariam).
[188] Exh. No. 451 30:n.1 (Mariam).
[189] Exh. No. 125 6, 15-27 (Dubin); Exh. No. 82C 24:2-9 (Ryan).
[190] Exh. No. 125 21:11-13 (Dubin).

Company provided the three-month average of the forward prices ending September 30, 2004. This price would be \$5.60 per MMBtu for the Sumas market hub.[192] Forward market prices since that time confirm that the Company's proposed rebuttal price is reasonable. The Company's update to its three-month average gas price forecast, for the three months ending December 15, 2004, reflect a projected price of \$6.25 per MMBtu at the Sumas hub.[193] Dr. Mariam's updated average of three-month averages for the twelve months ending December 15, 2004, shows prices for the rate year of \$5.38 per MMBtu, even including stale data from late 2003 and early 2004.[194]

80. ICNU proposes that the appropriate gas price to employ in calculating the base power cost in this proceeding should be based on fundamentals-based forecasts rather than forward market prices and should focus on the period beyond July 1, 2006.[195] For rate setting purposes, the Company needs to have a price determination methodology that provides information about the rate year that can be updated in a timely manner. Fundamental forecasts are developed intermittently, tend to use standardized time periods that do not necessarily correspond to the time periods of the Company's rate years, and use near-term price forecasts that are consistent with the forward markets at the time the forecasts are developed but quickly become stale. By contrast, forward market prices are readily available.[196]

81. ICNU attempts to add weight to its proposal by referencing gas price projections that the Company has itself used for planning and financial disclosure purposes. However, the information in Mr. Schoenbeck's charts was used by the Company for long-term resource

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[191] TR. 730:16 – 731:17 & 734:4 – 735:4 (Mariam).
[192] Exh. No. 82C 21:11-12 (Ryan).
[193] Exh. No. 11.
[194] Exh. No. 13 (final page).
[195] Exh. No. 371HC 17:13 – 19:3 (Schoenbeck).

planning and acquisitions with a longer time horizon than the rate year. Even for those purposes, that price information is now stale.[197] For example, long-term price forecasts have been predicting lower prices over the longer term, based on anticipation that significant added capacity of imported liquefied natural gas (LNG) will create a temporary dip in market gas prices. However, new potential market fundamentals, even if they occur, are not expected to affect natural gas market prices during the rate year.[198]

b. Coal Costs

82. The Company and Staff agree that cost of coal for the rate year has increased. On rebuttal, the Company corrected minor errors in Staff's statement of the increase in average coal price for the Colstrip Units. The correct average cost of coal is (i) $0.6122/MMBtu for Colstrip Units 1 and 2 and (ii) $0.6220/MMBtu for Colstrip Units 3 and 4.[199]

c. Oil Costs

83. This section is a placeholder for an argument ICNU has not yet advanced. The Company will address this issue in its reply brief, if necessary.

d. Hydro Normalization

84. In its initial testimony, the Company proposed to use sixty water years in modeling forecasted hydroelectric generation during the rate year.[200] Consistent with the Commission's

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[196] Exh. No. 82C 19:7-12 & 20:8-18 (Ryan).
[197] Exh. No. 82C 20:19 – 21:3 (Ryan); Exh. No. 12HC.
[198] Exh. No. 66C 24:12-20 (Markell).
[199] *Compare* Exh. No. 451 34:6-9 (Mariam) *with* Exh. No. 66C 18:9 – 20:7 (Markell); *see also* Exh. No. 82C 24:12 – 25:3-4 (Ryan); Exh. No. 66C 20:5-7 (Markell). Note that the Company's corrections reflect a slightly lower cost than stated by Staff on Colstrip Units 1 & 2 and a slightly higher cost on Colstrip Units 3 & 4. *See* Exh. No. 451 34:12-19 (Mariam).
[200] Exh. No. 111 5:4-13 (Dubin).

direction in Puget Sound Power & Light Company's 1992 rate case,[201] the Company supported its proposal with extensive analysis by an expert statistician. Dr. Dubin testified that using too little data can produce bias in the estimation,[202] and that evidence on this issue in prior proceedings was developed through erroneous techniques that resulted in incorrect conclusions about the reliability of the full set of water years.[203] Dr. Dubin ultimately concluded that the entire 60-year period of data from 1928-1987 should be used to forecast projected generation during the rate year.[204]

85. Staff also undertook analyses similar to that of Dr. Dubin and arrived at the same results—that the data are normally distributed and show no trend.[205] Staff, however, disagreed with the use of the full sixty years of streamflow data because the rule curves that the Northwest Power Pool and federal agencies such as BPA develop and apply to run off volumes are not yet agreed upon for the most recent ten years.[206] Thus, Staff recommended that data from the period 1928-1977 should be used.[207] For purposes of this proceeding, the Company is willing to use this fifty-year period in projecting power costs for the rate year.[208]

86. ICNU and Public Counsel did not present any evidence in their direct cases on the hydro issue. At the hearing, Mr. Schoenbeck proposed the use of 110 years worth of water data for The

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201 *WUTC v. Puget Sound Power & Light Co.*, Docket Nos. UE-920433, *et al.*, Eleventh Supp. Order at 43 (Sept. 1993) (directing the Company to continue using a 40-year rolling average and stating: "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.").
202 Exh. No. 111 18:14 – 19:1 & 30:1 – 31:12 (Dubin).
203 *Id.* at 18:1-13; TR. 641:24 – 643:11 (Dubin).
204 Exh. No. 111 5:8-11 (Dubin).
205 Exh. No. 451 25:1-2 (Mariam).
206 Exh. No. 451 20:1 – 21:3 (Mariam).
207 Exh. No. 451 20:20 – 21:3 (Mariam).
208 Exh. No. 82C 13:8-10 (Ryan).

Dalles, Oregon.[209] The Commission has rejected prior proposals to use this data,[210] and ICNU presented no data or analysis in this proceeding regarding the 110 year water data. The little evidence that exists in this proceeding on the topic is that the data is not hydrologically associated with the Company's resources, as The Dalles includes runoff from the Snake River system as well as the Columbia River system. Dr. Dubin and Staff analyzed the entire data set that was available related to the Company's Mid-Columbia and Westside projects.[211]

e. BPA Transmission Rate

87. The Company updated its estimated increase in transmission expenses on the BPA system based on the outcome of settlement discussions in BPA's 2006-07 transmission rate case.[212] On December 6, 2004, BPA Transmission Business Line (TBL) offered a proposed TBL Rate Case Settlement Agreement to TBL's individual customers and umbrella organizations. 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%.[213] In the unlikely event that BPA or the FERC rejected the TBL Rate Case Settlement Agreement, that would result in higher, not lower, transmission rates.[214] Thus, the Company's proposed increase of the TBL IR Rate to 17.7% as of October 1, 2005, should be included in the Company's revenue requirement.

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209 TR. 995:1 – 996:15 (Schoenbeck).

210 *WUTC v. Wash. Water Power Co.*, Cause No. U-83-26, Fifth Supp. Order at 23 (Jan. 1984)*; WUTC v. Wash. Water Power Co.*, Cause No. U-84-28, Second Supp. Order at 14 (Jan. 1985)*; WUTC v. Puget Sound Power & Light Co.*, Docket Nos. UE-920433, *et al.*, Eleventh Supp. Order at 42-43 (Sept. 1993).

211 Exh. No. 111 4:12-15, 8:11-13, 8:16 – 9:11, 10:2-6 & 11:9-17 (Dubin); TR. 661:16 – 663:5, 669:12 – 671:7, 682:23 – 683:5 & 683:24 – 684:16 (Dubin).

212 Exh. No. 82C 14:16 – 15:12 (Ryan).

213 Exh. No. 107 1 & 8:11 (Ryan).

214 TR. 963:16 – 964:10 (Schoenbeck).

2. Adjustment 2.04—Sales for Resale

88. Adjustment 2.04 adjusts the revenue for "Sales for Resale/Other Utilities and Wheeling for Others" to rate year projections per the results of the AURORA model run supporting the rate year power cost projections. Thus, it is dependent on the assumptions used in the AURORA model for the power cost adjustment (Adjustment 2.03).[215] For the reasons stated above, the Commission should approve the Company's proposed power costs and, accordingly, the Company's Adjustment 2.04—Sales for Resale.[216]

3. Adjustment 2.06—Tax Benefit of Proforma Interest

89. Adjustment 2.06 provides customers the tax benefit associated with the interest on debt used to support rate base and construction work in progress that has associated tax deductible interest.[217] The difference between Staff and the Company is a consequence of (i) different final rate base determinations and (ii) the effective interest rate as determined by the capital structure.[218] Adjustment 2.06 should be revised as appropriate based on the Commission's rulings on disputed rate base and capital structure issues.

4. Adjustment 2.10—Miscellaneous Operating Expenses

a. Incentive/Merit Pay and Associated Payroll Taxes

90. The Company's proposed Adjustment 2.10 is based on incentive plan payment expenses incurred during the test year.[219] The test period amount of $3,440,174 is significantly less than the Company's incentive payment expense history over the past five years, the average of which

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[215] Exh. No. 231 8:15-19 (Story); Exh. No. 421 9:8-9 (Russell); Exh. No. 237C 15:8-9 (Story).
[216] Exh. No. 237C 15:9-10 (Story); Exh. No. 238C 2.04:1 (Story).
[217] Exh. No. 231 9:11-15 (Story).
[218] Exh. No. 421 9:17 – 10:2 (Russell); Exh. No. 237C 15:16-19 (Story); Exh. 238C 2.06:20 (Story).
[219] Exh. No. 333 2:13 – 3:5 (Hunt); TR. 809:19 – 810:8 (Parvinen).

is $5,027,451. It is also less than the average incentive plan expense during the past three years, which is $3,827,774.[220]

91. Staff proposes to begin with the expense amount paid in 2004 for performance during 2003—$2,096,420.[221] This was the lowest payout in the past five years.[222] Staff proposes to then reduce this amount to $1,316,941, on the basis that portions of the incentive payments are "associated or tied to earnings." In support of this reduction, Staff cited Commission orders in which incentive plan expenses have been disallowed in the past.[223]

92. In contrast to prior cases, the Company's incentive payment plan is squarely within the types of incentive plans endorsed by the Commission:

> The Commission believes . . . that the company can do a far better job in the future by creating incentives and setting goals that advantage ratepayers as well as shareholders. Such goals might include controlling costs, promoting energy efficiency, providing good customer service, and promoting safety.[224]

The Company's plan focuses on goals that directly benefit ratepayers such as customer service, service quality, safety, reliability, and efficient operations.[225] Unlike the disallowed plans cited by Staff, the Company's plan does not permit "financial rewards to eclipse customer service failures," and it thus does not send "the message to employees that service quality is much less important than financial performance."[226] If the earnings per share target is achieved but the

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[220] Exh. No. 333 2:13 – 3:5 (Hunt).
[221] Exh. No. 441 12:5-8 (Parvinen).
[222] Exh. No. 333 2:20-21 (Hunt); Exh. No. 333 3:Chart (Hunt).
[223] Exh. No. 441 12:9-15 (Parvinen); Exh. No. 423C 12:2 (Russell); Exh. No. 443 7:3 (Parvinen).
[224] *WUTC v. Wash. Natural Gas Co.*, Cause No. UG-920840, Fourth Supp. Order at 19 (Sept. 1993).
[225] Exh. No. 333 4:12-17 (Hunt); Exh. No. 335 11 & 12 (Hunt).
[226] *WUTC v. U.S. WEST Communications, Inc.*, Cause No. UT-950200, Fifteenth Supp. Order at 49 (Apr. 1996).

Company's service levels are not achieved, there is no payout on the earnings goal.[227]

93. At hearing, Mr. Parvinen testified that Staff's proposed starting amount of $2,096,420 was appropriate because the Company will not reach its earnings target for calendar year 2004, so no incentive payments will be made during calendar year 2005.[228] It is premature to make such a prediction at this time. Even if there were no payout in 2005 for performance year 2004, that would be the first time in six years that the Company has incurred no such expense. The six-year average of incentive plan payments that included a $0 incentive plan payment for calendar year 2004 would be $4,189,542 and the four-year average expense for performance years 2001 through 2004 would be $2,870,831.[229]

94. The Company acknowledges that this expense could be normalized in a number of different ways. However, any of the plausible methods for such normalization yield a significantly higher number than Staff's, and no reduction should be imposed related to the structure of PSE's incentive plan. The Commission should approve for inclusion in rates the Company's proposed level of incentive payment plan expense.[230]

b. Deloitte Fee for Income Tax Advice

95. Staff proposes to remove, from the Electric Results of Operations, the $812,196 the Company paid to Deloitte & Touche during the test year for tax advice.[231] This payment to Deloitte is an appropriate business practice and ongoing expense because tax law and regulatory interpretations are constantly subject to change. Hiring outside experts allows the Company to

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[227] Exh. No. 333 6:2-3 (Hunt); Exh. No. 335 3 (Hunt).
[228] TR. 812:23 – 813:13 (Parvinen).
[229] *See* Exh. No. 333 3 (table) (Hunt).
[230] Exh. No. 238C 15 (Story).
[231] Exh. No. 423C 12:4 (Russell).

gain the benefit of their extensive staffs and experience.[232]

96. Staff seeks to support its proposed disallowance by pointing to a restating adjustment the Company made for a one-time Montana Corporate License Tax refund (Electric Adjustment 2.25)[233] that Staff describes as resulting from the "retroactive restatement of the tax basis of PSE's assets."[234] This "retroactive restatement of the tax basis of PSE's assets" is actually related to the $72 million dollar deferred tax reduction to rate base that resulted from the work done by Deloitte.[235] This potential tax benefit results in a combined revenue requirement savings to the Company's electric and gas customers of approximately $10 million in the current rate proceeding and will continue to benefit customers over the next twenty years if the Company's deductions are ultimately upheld.[236] The Company should continue to recover in its rates sufficient funds to engage consultants such as Deloitte in the future.[237]

5. Adjustment 2.11—Property Taxes

97. Both the Company and Staff used an estimate of levy rates in their prefiled direct cases to calculate property taxes. The Company updated Adjustment 2.11 in its rebuttal testimony to reflect actual current levy rates.[238] The Company understands that this aspect of Adjustment 2.11 is not in dispute. However, Staff also removed a payment to the Oregon Department of Revenue related to property taxes for 1995 through 2001 on the 3rd AC transmission line. By contrast, the

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232 Exh. No. 237C 17:7-11 (Story).
233 Exh. No. 238C 30 (Story).
234 Exh. No. 421 6:14 (Russell).
235 Exh. No. 237C 17:16-20, 18:6-17 (Story).
236 Exh. No. 237C 17:20 – 18:2 (Story).
237 Exh. No. 237C 18:18 – 19:1 & 34:20 – 35:9 (Story); Exh. No. 139 9:10 – 10:11 (McLain). *See also POWER*, 104 Wn.2d at 811.
238 Exh. No. 237C 19:5-8 (Story).

Company proposes to amortize the payment of this assessment over three years.[239]

98. These taxes were the subject of litigation for several years by one of the parties with an interest in the 3rd AC. Following an adverse ruling by the Oregon Supreme Court, the Oregon Department of Revenue billed the Company for back property taxes in late 2002, which was the first time that Company was actually assessed for the taxes. The Company was ultimately able to reach a settlement with the Oregon Department of Revenue, and the amount that the Company is seeking to recover is the tax settlement amount (which is 75% of the original amount assessed for the 1995 through 2001 tax periods), which the Company paid during the test year. The Company should not be penalized for contesting questionable tax assessments, particularly when the taxing authority had not even billed the Company until the fall of 2002.[240]

6. Adjustment 2.15—Montana Energy Tax

99. The Company understands that Adjustment 2.15 is now uncontested.

7. Adjustment 2.18—Rate Case Expense

a. Cost Treatment (deferral and amortization vs. expense)

100. The Company has treated its rate case expenses the same in this case as it and the Commission have for over 20 years: by prefiling in its direct testimony an estimate of actual costs it will incur for the case, then later updating those costs for actuals. During this time period, the question has been whether to amortize the actual costs of a rate case for recovery over two or three years and whether any specific costs from that case should be disallowed.[241]

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[239] Exh. No. 237C 19:9-12 & 20:10-12 (Story); Exh. No. 238C 16(2.11):5-7 (Story).

[240] Exh. No. 237C 19:15 – 20:10 (Story).

[241] Exh. 237C 21:20 – 24:21 (Story); TR. at 831:24 – 839:3 (Russell); Exh. No. 429 3 (Russell); Exh. No. 430 3 (Russell); Exh. No. 431 2:15 & 3:17 – 4:5 (Russell); Exh. No. 432 2-3 (Russell); Exh. No. 433 2 (Russell); Exh. No. 434 3:16-18 & 5 (Russell); Exh. No. 435 3:18-23 (Russell). *See also WUTC v. Puget Sound Power & Light Co.,*

Amortization of the actual amount of costs incurred for rate cases for recovery over some period of time is typical in other jurisdictions as well.[242]

101. The Company does not believe that the Commission should change this historic treatment and begin treating general rate case costs through expensing and normalizing them. Typically, nearly all of the expenses associated with a general rate case would be incurred after the end of the test year for that rate case. They are also incurred on an irregular basis and can be highly variable.[243] Thus, it does not make sense to address these costs through normalization, and future disputes about the proper "normalization" amount are likely to be highly contentious.

b. Amount for Recovery

102. Staff does not propose any reduction in the amount the Company has incurred for rate case costs.[244] ICNU implies generally that the Company is paying too much in rate case costs, without challenging any specific cost item.[245] ICNU also complains that the Company's various rate case proposals have "left intervenors and ratepayer advocates struggling to keep up."[246] ICNU proposes creation of a mechanism through which the Company would fund the costs of intervenor participation in rate cases at some future time. Until then, ICNU advocate imposing a blanket disallowance in this and future proceedings of 50% of the Company's rate case costs.[247]

Cause No. U-81-41, Sixth Supp. Order at 19 (Dec. 1988) ("The Commission notes that it has on rare occasions authorized the recovery of past expenses in instances where doing so is consistent with the public interest and sound regulatory theory. [For example,] amortization of rate case expense.").

[242] *See, e.g., Driscoll v. Edison Light & Power Co.*, 307 U.S. 104, 121 (1939) (approving amortization of rate case expenses because "[t]here could rarely be an anticipation of annually recurring charges for rate regulation"); *Re Delta Nat. Gas Co., Inc.*, 198 PUR 4th 132, 142 (Ky. PSC 1999) (rejecting proposal to normalize rather than amortize rate case expenses).

[243] Exh. No. 237C 24:2-21 (Story); TR. 839:4-16 (Russell).

[244] Exh. No. 421 20:16-19 (Russell); Exh. No. 423C 20:3-9 (Russell).

[245] Exh. No. 371HC 28:18 – 29:2 (Schoenbeck).

[246] Exh. No. 371HC 28:9-12 (Schoenbeck).

[247] Exh. No. 371HC 29:3 – 17 (Schoenbeck).

103. It would be premature to take a position at this time on ICNU's call for future implementation of an intervenor funding mechanism. However, the Company notes that the mechanism in Oregon is specifically authorized by statute, and was implemented through a commission rulemaking proceeding.[248] Moreover, the statute mandates that "[t]he commission shall allow a public utility that provides financial assistance under this section to recover the amounts so provided in rates."[249] It would be fundamentally inconsistent with at least one of the intervenor funding mechanisms that ICNU cites to force shareholders to absorb 50% of rate case costs until such a mechanism is in place in Washington.

104. Adoption of ICNU's blanket proposal to disallow 50% of the Company's rate case costs would also be arbitrary and represent legal error. "Expenses . . . are facts . . .. If properly incurred, they must be allowed as part of the composition of the rates. Otherwise, the so-called allowance of a return upon the investment, being an amount over and above expenses, would be a farce."[250] As the Commission has recognized, rate case costs are "a legitimate expense incurred whenever the company must defend itself."[251] This is consistent with the general rule that prudently incurred rate case expenses are properly recoverable in rates as a necessary cost of a regulated utility in carrying out its business.[252] The suggestion that a utility's rate case costs should be borne primarily by or even shared by shareholders has been consistently rejected.[253]

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[248] Or. Rev. Stat. § 757.072; Or. Admin. R. 860-012-0100; Or. Admin. R. 860-012-0190.

[249] Or. Rev. Stat. § 757.072(4).

[250] *POWER*, 104 Wn.2d at 817-18.

[251] *WUTC v. Puget Sound Power & Light Co.*, Cause No. U-85-53, Second Supp. Order at 42 (May 1986).

[252] *See Driscoll v. Edison Light & Power Co.*, 307 U.S. 104, 120-21 (1939) ("[T]he utility should be allowed its fair and proper expenses for presenting its side to the commission."); *West Ohio Gas Co. v. Public Utils. Comm'n of Ohio*, 294 U.S. 63, 73 (1935) ("The charges of engineers and counsel, incurred in defense of its security and perhaps its very life, were as appropriate and even necessary as expenses could well be.").

[253] *See, e.g., Re Duke Power Co.*, 79 PUR 4th 145, 175 (S.C. PSC 1986) (commission rejects sharing of rate case expenses between shareholders and customers); *Re Cincinnati Gas & Elec. Co.*, 42 PUR 4th 252, 278 (Ohio

105. The Company has been making significant efforts to control its legal costs. It has expanded its in-house legal department, analyzed and implemented changes in its management of legal services, and relied to a greater extent on Company employees to handle or assist with regulatory filings.[254] The Company bears the burden of proof in a rate case, must file extensive direct and rebuttal testimony, cannot limit the amount of data requests or issues advanced by other parties, and must address all issues that are raised by all other parties. The Company's costs incurred for this case should not be disallowed.

8. Adjustment 2.20—Property and Liability Insurance

106. Adjustment 2.20 reflects expected contractual increases for property and liability insurance, updated for actual contract increase and decreases as they become known.[255] In its rebuttal filing, the Company updated for actual costs that were known at that time.[256]

9. Adjustment 2.22—Wage Increase

107. Two differences originally existed between Company and Staff with respect to Adjustment 2.22, but only one difference remains. The first related to the calculation of "slippage," and, on rebuttal, the Company agreed with Staff's calculation and revised its wage adjustment accordingly.[257] The second difference relates to the Company's pro forma 2005 increase for non-union employees. Staff proposed removal of the 2005 increase because it is not "known and measurable."[258] However, consistent with established industry practice, the

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PUC 1981) (commission dismisses "out of hand" suggestion that rate case expense should be excluded because it "results in a direct and primary benefit to the company's investors").

[254] Exh. No. 237C 30:2 – 32:18 (Story); Exh. No. 240C (Story)

[255] Exh. No. 441 13:13-15; 19:6-10 (Parvinen); Exh. No. 264 6:17-22 (Luscier).

[256] Exh. No. 264 6:20-22 (Luscier); Exh. No. 237C 29:9-10 (Story); Exh. 238C 25:7 (Story).

[257] Exh. No. 264 7:1-3 (Luscier).

[258] Exh. No. 441 14:13-17 (Parvinen).

Company has implemented annual merit salary increases for its non-union employees every year for many years.[259] Since 1998, the Company's annual merit pay award budget has been 3% Company-wide for non-represented employees, which is in the lower end of competitive practice in the industry.[260]

108. 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. 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.[261]

10. Adjustment 2.23—Investment Plan

109. Adjustment 2.23 adjusts the Company's portion of investment plan expense to reflect the additional expense associated with wage increases.[262] The difference between the two adjustments results from the differing positions regarding Adjustment 2.22. Adjustment 2.23 should be revised consistent with the Commission's determination on Adjustment 2.22.

11. Adjustment 2.30—Production Adjustment Effect

110. Adjustment 2.30 reflects all the production related expenses and rate base items that have been revised through other adjustments.[263] As with power costs, these items are adjusted from a rate year basis to a test year basis using a production factor,[264] which is 98.719%.[265] The

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[259] Exh. No. 333 7:13-15 (Hunt).
[260] Exh. No. 333 7:13 – 8:6 (Hunt); Exh. No. 336 1 (Hunt).
[261] Exh. No. 333 7:15 – 8:16 (Hunt); Exh. No. 237C 29:12 (Story); Exh. 238C 27 (Story).
[262] Exh. No. 231 16:10-12 (Story); Exh. No. 237C 29:13 (Story); Exh. No. 238C 28:18 (Story).
[263] Exh. No. 421 28:9-11 (Russell); Exh. No. 237C 26:12-13 (Story).
[264] Exh. No. 237C 26:13-15 (Story).
[265] Exh. No. 231 20:18 – 21:4 (Story); Exh. No. 237C 26:12-15 (Story).

Company and Staff agree that this equates to a 1.281% reduction applied to various power-related costs.[266] However, because some of the costs to which the production factor applies are based on contested adjustments, the net operating income and rate base results of the Company and Staff differ.[267] Adjustment 2.30 should be revised as appropriate based on the Commission's rulings on disputed issues in the case.

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

111. The only remaining contested issue on these items relates to rate case expenses the Company incurred for its 2001-02 general rate case, Docket Nos. UE-011570, *et al.*[268] Consistent with the settlement agreement in that case, the actual amount of the Company's expenses for that case were deferred and amortized for recovery over three years.[269] Staff is objecting to including the remaining 2001 rate case costs or the approved amount of 2004 rate case costs in Account 182.3. Instead, Staff argues that these deferred rate case costs should be included in Account 186. Staff states that recording these costs in Account 182.3 causes these amounts to be included in working capital and to earn the Company's authorized rate of return during the one to three years that they are being recovered in rates, while recording them in Account 186 causes the amounts to be excluded from working capital.[270]

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[266] Exh. No. 421 28:9-11 (Russell); Exh. No. 231 21:4-5 (Story); Exh. No. 237C 26:15-16 (Story).

[267] *Compare* Exh. No. 237C 26:16-19 (Story) and Exh. No. 238C E8-D:35 (Story) *with* Exh. No. 421 28:12-13 (Russell); Exh. No. 423 32:22 (Russell); and Exh. No. 423 32:49 (Russell).

[268] Exh. No. 238C 1 (Summary):35 (Story); Exh. No. 422C 1:35 (Russell).

[269] *See WUTC v. Puget Sound Energy, Inc.*, Cause Nos. UE-011570, *et al.*, Settlement Terms for Electric Revenue Requirements, Common Cost and Overall Rate of Return, Exhibit B, at 3, ¶ 7 (stating "[a]mortization of deferred electric rate case expense has been adjusted to $767,264 annually"), and *WUTC v. Puget Sound Energy, Inc.*, Cause Nos. UE-011570, *et al.*, Settlement Terms for Natural Gas Revenue Requirements, Including Common Cost Allocation, and Line Extension, Exhibit A at 2, ¶ 7 (stating "[a]mortization of deferred gas rate case expense has been adjusted to $600,922 annually").

[270] Exh. 421 19:13 – 20:14 & 21:8-10 (Russell); Exh. 441 7:15 – 8:2 (Parvinen); Exh. 444 2:57 (electric) & 4:47 (gas) (Parvinen).

112. Whether a cost is included in Account 182.3 or in Account 186 does not determine whether it is included in working capital; rather, it is the Commission that determines whether such costs are to be included in working capital.[271] Inclusion of rate case costs in working capital would also be consistent with the Commission's historic treatment of such costs.[272] Rate case costs represent funds that have been expended to support utility operations but are not reflected in rate base and would not earn a return but for inclusion in working capital. Because these costs are amortized for recovery over a longer time frame than if the entire amount were included in the rate year, the Company loses the time value of money during the time period between when these costs are approved for recovery and when they are actually recovered in rates. This is precisely the type of situation for which working capital exists.[273] If the Company is not permitted to earn a return on costs it has incurred that are amortized for recovery, it will not be allowed to recover its cost of capital, causing further earnings degradation.[274]

C. Contested Adjustments—Gas[275]

1. Adjustment 2.01—Revenue & Purchased Gas

113. Gas Adjustment 2.01 normalizes weather-sensitive gas therm sales that occurred during the test year by calculating the relationship between temperature during the test year and gas consumption during the test year. The adjustment then restates therms sold to reflect therms that would have been sold had temperatures been "normal" and then reprices the adjusted therms sold

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[271] Exh. No. 237C 25:15-19 (Story).

[272] Exh. No. 252 1 (last 2 paragraphs) – 2 and Attachment C (Story).

[273] Exh. 237C 28:6-21 (Story); Exh. 239 (next to final page):47 & (final page):92-101 (Story); Exh. 261 10:17 – 11:1 (Luscier); Exh. 264 8:17 – 9:12 & 11:10 – 12:7 (Luscier); Exh. 266 6:67-78 (Luscier).

[274] *See, e.g.*, Exh. No. 151 8:13 – 9:14 (Valdman); Exh. No. 154 21:6-21 (Valdman); TR. 220:13 – 224:1 (Valdman); Exh. No. 201 11:1 – 21:19 (Cicchetti); TR. 329:18 – 334:3 (Cicchetti); TR. 841:5 – 843:24 (Russell).

[275] Appendix D sets forth a list of the contested gas adjustments and associated differences in NOI and rate base, as well as a list of the gas adjustments PSE understands are uncontested.

based upon the authorized weighted-average cost of gas.[276]

114. The Company's and Staff's respective Adjustment 2.01 differ by $2,405,896 in net operating income.[277] The difference is due primarily to a disagreement about which set of "normal" weather data to use to perform this calculation.[278] This issue is being considered in the weather normalization collaborative that was commenced as part of Docket No. UE-031725.[279]

115. Consistent with the gas weather normalization methodology approved by the Commission in prior proceedings, the Company computed normal temperature using a twenty-year rolling average of National Oceanic and Atmospheric Administration (NOAA) temperature data ending September 2003, less the highest and lowest years.[280] Staff proposes to replace the Commission-approved methodology with a rolling thirty year average (three ten-year datasets) of NOAA data ending in the year 2000.[281] Staff also makes a number of recommendations for future rate proceedings, but these do not have any impact in the current proceeding.[282]

116. The Company is receptive to approaches other than the Commission-approved historic methodology, but Staff's proposal is premature and not sufficiently developed for adoption.[283] In particular, the Company is concerned about the inconsistencies associated with using test year usage and weather data to develop the coefficients, and then applying a data set of "normal"

[276] Exh. No. 451 40:13-18 (Mariam); Exh. No. 261 3:7-11 (Luscier).
[277] Exh. No. 265 2.01:37 (Luscier); Exh. No. 441 11:1-2 (Parvinen); Exh. No. 443 1:37 (Parvinen).
[278] Exh. No. 441 10:22-26 (Parvinen); Exh. No. 264 5:4-8 (Luscier).
[279] Exh. No. 284 13:9 – 14:4 (Heidell); *WUTC v. Puget Sound Energy, Inc.*, Cause No. UE-031725, Tenth Supp. Order (Feb. 2004); TR. 594: 17-20 (Heidell).
[280] Exh. No. 284 15:19-21 (Heidell); *WUTC v. Wash. Nat. Gas Co.*, Docket No. UG-920840, Fourth Supp. Order at 17-18 (Sept. 1993).
[281] Exh. No. 451 44:1-10 (Mariam).
[282] Exh. No. 451 42:1-6 (Mariam).
[283] Exh. No. 284 17:8-11 (Heidell).

weather that actually ends several years before the test year.[284] The Company's twenty-year rolling average, on the other hand, is proven and is sufficiently accurate to develop the necessary equations and calculations.[285] While there was significant discussion at hearing about problems that can exist with respect to rolling averages, both the Company's 20-year data set and Staff's proposed 30-year data set are rolling averages. These are just two examples of the technical questions that should be addressed and worked through as part of the pending collaborative.

2. Adjustment 2.03—Tax Benefit of Proforma Interest

117. Gas Adjustment 2.03 should be revised as appropriate based on the Commission's determinations, as discussed in Section IV(A)(3), above.[286]

3. Adjustment 2.07—Miscellaneous Operating Expenses (Incentive/Merit Pay and Associated Payroll Taxes)

118. Gas Adjustment 2.07 should be approved for the reasons set forth in the Company's discussion of Electric Adjustment 2.10, Section IV(A)(4)(a), above.[287]

4. Adjustment 2.10—Rate Case Expense

119. Gas Adjustment 2.10 should be approved for the reasons set forth in the Company's discussion of Electric Adjustment 2.18, Section IV(A)(7), above.[288]

5. Adjustment 2.11—Property and Liability Insurance

120. Gas Adjustment 2.11 should be approved for the reasons set forth in the Company's discussion of Electric Adjustment 2.20, Section IV(A)(8), above.[289]

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284 Exh. No. 284 15:1-5 (Heidell); Exh. No. 284 16:8-10 (Heidell); TR. 593:6-10 (Heidell).
285 Exh. No. 284 16:2-6 (Heidell).
286 Exh. No. 261 4:9-13 (Luscier); Exh. No. 264 4:3-6 (Luscier); Exh. 265 2.03 (Luscier).
287 Exh. No. 264 6:7-16 (Luscier); Exh. No. 265 2.07 (Luscier).
288 Exh. No. 265 2:10 (Luscier).
289 Exh. No. 264 6:17-23 (Luscier); Exh. 265 2.11 (Luscier).

6. Adjustment 2.13—Wage Increase

121. Gas Adjustment 2.13 should be approved for the reasons set forth in the Company's discussion of Electric Adjustment 2.22, Section IV(A)(9), above.[290]

7. Adjustment 2.14—Investment Plan

122. Gas Adjustment 2.14 should be revised as appropriate based on the Commission's ruling on the wage increase issue (Electric Adjustments 2.22 and 2.23)[291]

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

123. Staff seeks to eliminate $8,137,320 of operating revenues,[292] to add back $606,509 of operating income and to reduce rate base by $31,312,542 related to the Company's Gas Water Heater and Conversion Burner Rental Program.[293] Staff asserts that removal of these amounts is appropriate under the settlement approved by the Commission in the Company's last general rate case related to water heater and conversion burner rentals (the "Water Heater Settlement").[294]

124. 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.[295] The Company agreed that it would not request an increase in the revenue requirement associated with the gas rental business until September 1, 2005.[296] Paragraph 5 of the Water Heater Settlement states as follows:

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[290] Exh. No. 264 7:1-6 (Luscier); Exh. No. 265 2.13 (Luscier).

[291] Exh. No. 264 7:7-9 (Luscier); Exh. No. 265 2.14 (Luscier).

[292] Exh. No. 443 18:3 (Parvinen).

[293] Exh. No. 441 16:7 – 17:3 (Parvinen).

[294] *WUTC v. Puget Sound Energy, Inc.*, Cause Nos. UE-011570, *et al.*, Settlement Terms for Natural Gas Revenue Requirements, Including Common Cost Allocation, and Line Extension, Exhibit A ("Water Heater Settlement"); Exh. No. 441 16:15 – 17:2 (Parvinen).

[295] Exh. No. 321 2:15 – 3:6 (Karzmar).

[296] Exh. No. 321 3:12-13 (Karzmar).

> 5. 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.[297]

The first sentence of paragraph 5 of the Water Heater Settlement mandates that the Company will not seek recovery in rates—before September 1, 2005—of any additional costs for the rental program beyond those built into rates based on the test year for the Company's last general rate case. The second sentence enforces the restriction of the first sentence by requiring removal of the gas water heater and conversion burner rental program costs, expenses and revenues from a general rate case if the Company violates the agreement by requesting an increase in revenue requirement for the rental program.[298]

125. Staff takes the second sentence of paragraph 5 of the Water Heater Settlement out of context and ignores the first sentence.[299] In doing so, Staff adopts an illogical interpretation of the Water Heater Settlement. Staff's interpretation would effectively mean 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. Rather, the two sentences in paragraph 5, read together, 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.

126. The Company has not requested an increase in the revenue requirement associated with

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[297] Water Heater Settlement at 2, ¶ 5.
[298] Exh. No. 321 4:5-12 (Karzmar).
[299] Exh. No. 321 4:8-12 (Karzmar).

its gas water heater and conversion burner rental program in this proceeding.[300] The proposed revenue requirement and amount spread to general rates related to the program in this case is $13,463,801.[301] The revenue requirement and amount spread to general rates related to the program in the Company's 2001 general rate case was $14,438,632.[302] Accordingly, the Company has requested a *decrease*—not an increase—of $974,831 in revenue requirement related to the gas water heater and conversion burner rental program.

127. The Commission should approve the Company's position on this issue as a policy matter, as well. The water heater and conversion burner rental program has been in existence and included in the Company's rates for over forty years. There is no logical reason to remove this element of the Company's rate base and associated expenses because the Company needs rate relief due to entirely unrelated cost pressures. Elimination of this investment and these expenses would be arbitrary and harmful to the Company's financial condition, would set poor precedent, and would impose further financial drag on the Company.[303]

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

128. The Company's inclusion of amortized rate case costs in working capital should be approved for the reasons set forth in Section IV(B), above.[304]

V. CATASTROPHIC EVENTS

129. Currently, the Company is authorized to defer and recover one-time expenses from extraordinary storm events over time, to help mitigate the financial impact of such events in the

[300] Exh. No. 321 5:8-13 (Karzmar).
[301] Exh. No. 324 3:15 (Karzmar).
[302] Exh. No. 441 16:16-18 (Parvinen).
[303] Exh. No. 321 8:2-17 (Karzmar); *POWER*, 104 Wn.2d at 811.
[304] Exh. No. 265 1:34 (Luscier); Exh. No. 442 1:34 (Parvinen).

year they occur.[305] Under this mechanism, a catastrophic storm is defined as an event where more than 25% of the Company's electric customers are without power due to weather-related causes.[306] The costs of storms that meet the threshold are deferred and, when approved for recovery by the Commission, amortized for recovery over 3 years.[307] Staff and the Company agree that the current threshold for extraordinary storm damage is inappropriate because the percent-of-customers threshold has no relation to the potential system impacts and related costs of an event.[308] Instead, "a predetermined level of 'costs' is a more appropriate trigger for determining whether costs should be deferred."[309]

130. In its initial filing, the Company requested that the Commission change the definition of "catastrophic storm" to "catastrophic event" and include damage to the Company's electric and/or gas infrastructure due to catastrophic natural events, such as windstorms, ice storms, and earthquakes, and also to cover manmade disasters such as terrorist attack.[310] The Company proposed that any costs of $2 million or more related to any such event would be deferred and, when approved for recovery by the Commission, amortized for recovery over three years.[311]

131. In its direct testimony, Staff proposed use of a dual trigger approach to defining catastrophic events to the electric system. Staff's proposal first uses the Institute of Electrical and Electronic Engineers, Inc. (IEEE) Standard (Std) 1366-2003, entitled *IEEE Guide for Electric Power Distribution Reliability Indices*, as a trigger for catastrophic damage as relates to the

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[305] Exh. No. 131C 27:12-19 (McLain).
[306] Exh. No. 131C 28:3-4 (McLain).
[307] Exh. No. 131C 28:6-7 (McLain); *see also,* Exh. No. 131C 28:10-12 (McLain); Exh. No. 233C 2.26:19 (Story); Exh. No. 238C 2.26:19 (Story).
[308] Exh. No. 131C 28:19 – 29:9 (McLain).
[309] Exh. No. 421 25:8-10 (Russell).
[310] Exh. No. 131C 30:2-9 (McLain).

electric system.[312] Although IEEE Std. 1366-2003 would not distinguish between storm and non-storm events, Staff has proposed that the Commission continue to restrict PSE's authorization for deferral treatment to electric storm damage costs.[313] For the second trigger, Staff proposed that the Commission

> set a threshold for March 2005 through December 31, 2005, at $5 million for all eligible IEEE major storm events. For the following two fiscal years, [Staff] recommend[s] that all IEEE major storm events costs totaling over $7 million be afforded deferral cost treatment.[314]

The Company does not oppose Staff's dual-trigger approach to defining electric catastrophic events if the dollar threshold level is set appropriately, as described below.[315] However, the definition should be modified slightly and should also be applied to non-storm natural events and manmade disasters.

132. The Company has proposed to modify the IEEE Std. 1366-2003 definition of an outage with respect to the length of time of an outage.[316] The Company currently defines a sustained interruption as any interruption lasting one minute or more, whereas the IEEE defines a sustained interruption as any event that lasts more than five minutes.[317] Staff does not oppose a modification of the time requirement to one minute.[318]

133. With respect to the cumulative, annual cost threshold, the Company believes that the threshold levels proposed by Staff are too high, and that a more appropriate annual threshold

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[311] Exh. No. 131C 30:16-21 (McLain).
[312] Exh. No. 471 (Kilpatrick).
[313] Exh. No. 421 26:13-16 (Russell); TR. 585:15 – 586:16 (Kilpatrick).
[314] Exh. No. 421 27:17 – 27:2 (Russell).
[315] Exh. No. 139 1:18 – 2:2 (McLain).
[316] Exh. No. 139 2:11-19 (McLain).
[317] Exh. No. 471 7:8-10 (Kilpatrick).
[318] TR. 588:25 – 589 (Kilpatrick).

would be $5 million.[319] For the partial 2005 calendar year, the cumulative threshold should be $3.5 million, rather than the $5 million proposed by Staff.[320] The Company proposes to lower the annual, cumulative threshold because, 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.[321] Based on the Company's experience over the past five years, the $5 million 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).[322]

134. In addition to storm damage, the catastrophic event definition should be expanded to include natural and manmade disasters, and should apply to the gas system as well as the electric system. A more comprehensive mechanism would provide greater financial predictability by limiting the risk that the Company may be forced to absorb extraordinary losses during a particular year that are beyond its control. At the same time, the Company's proposed expansion of the mechanism would spread these volatile and sometimes extreme costs over a longer period, providing more rate stability for customers.[323] The Commission would have continuing oversight over such deferrals because the Company is not proposing to change the reporting requirements of the existing mechanism.

135. For the gas system, the Company has proposed to set the threshold at $2 million or more

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[319] Exh. No. 139 4:5-7 (McLain).
[320] Exh. No. 139 4:11-14 (McLain).
[321] Exh. No. 139 4:20 – 5:1-8 (McLain); Exh. No. 141 (McLain).
[322] Exh. No. 139 5:9-13 (McLain); Exh. No. 141 (McLain).
[323] Exh. No. 139 2:2-8 (McLain).

per event.[324] Though the Company has never had an event of this magnitude impacting the gas system, it would be appropriate to have a deferral mechanism in place in advance of such an event, because it provides additional financial stability and would avoid the administrative burden to the Company and the Commission of a special filing, should such an event occur.[325]

136. Finally, Staff's proposal includes a thirty-day deadline after an event for the Company to file a report of deferral.[326] A thirty-day reporting period, however, would not provide the Company adequate time to ensure the integrity of storm or other catastrophic event data recorded in its system. Also, to the extent that a cost trigger is included in determining if an event qualifies for deferral, a thirty-day time period would not be sufficient for all event related costs to be recorded in the Company's system. Therefore, a reporting period of ninety days is more appropriate.[327]

VI. RATE SPREAD AND RATE DESIGN SETTLEMENT

137. The parties agree that the Commission should approve the Partial Settlement Agreement on rate spread and rate design.[328]

VII. PCORC COSTS (DOCKET NO. UE-031471)

138. Staff and ICNU request that the Commission deny the PCORC accounting petition in Docket No. UE-031471, and instead normalize and include in rates some amount for PCORC proceedings as an ongoing expense. Staff witness Mr. Russell proposed to include in rates $650,000 (one-half of the total $1.3 million in 2003 PCORC costs) "as a 'normal' level of

[324] Exh. No. 131 30:16-21 (McLain).
[325] Exh. No. 139 5:22 – 6:4 (McLain).
[326] Exh. No. 421 28:2-5 (Russell).
[327] Exh. No. 139 7:17 – 8:2 (McLain).
[328] *See* Exh. No. 1; Exh. No. 2.

PCORC costs going forward."[329] The Company does not object to Staff's proposal to deny the Company's deferred accounting petition in Docket No. UE-031471 and instead include $650,000 as a normalized level of PCORC costs in rates.[330] This treatment avoids any double recovery because, as Staff acknowledges, the Company expensed its test year PCORC costs ($401,000) because its deferred accounting petition was never granted.[331]

139. However, the Company discovered in preparing this brief that Mr. Russell's proposed adjustment is not consistent with his testimony. Instead, he further reduced his $650,000 normalized PCORC cost by spreading it over three years. The result would be a normalized PCORC cost amount of only $216,666 per year. This amount is far too low. The Company will be adding resources over the next several years and will likely be filing PCORCs on a regular basis.[332] The Company's 2003 PCORC costs were $1.3 million. Staff's adjustment would only provide sufficient cost recovery for one PCORC every six years. Even if the costs of future PCORCs were half of the first, Staff's adjustment would only permit one PCORC every three years. ICNU arrives at a similar proposed adjustment by asking the Commission to first reduce the amount of 2003 PCORC expenses to $500,000 as a normalized amount for such expenses, and then require shareholders to absorb half of that amount on an ongoing basis.[333]

140. Adoption of Staff or ICNU's proposed "normalized" amounts for this adjustment would be arbitrary and unlawful, for the reasons set forth in Section IV(A)(7)(b), above.

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[329] Exh. No. 421 18:1-10 (Russell).
[330] Exh. No. 237C 21:13-19 (Story).
[331] Exh. No. 421 18:17-19 (Russell).
[332] Exh. No. 61C 3:10 – 10:4 (Markell); TR. 762:5 -24 (Story).
[333] Exh. No. 371HC 30:17-23 (Schoenbeck).

VIII. WHITE RIVER (DOCKET NO. UE-032043)

141. The Company and Staff agree on the accounting treatment that should be approved for the Company's White River hydroelectric project (Lake Tapps), which ceased operation on January 15, 2004.[334] In order to authorize the agreed accounting treatment, the Commission's order in this proceeding should set forth the language proposed in Mr. Russell's testimony.[335]

142. In its prefiled testimony, Staff also updated the deferral of costs associated with the Company's FERC licensing effort and with securing a water right by including payments the Company received from Cascade Water Alliance ($3 million) after the test year.[336] The Company agrees with Staff's update.[337]

IX. COMMISSION AUTHORITY TO APPROVE REVENUES ABOVE AMOUNTS PRODUCED BY THE TARIFF SHEETS FILED ON APRIL 5, 2004

143. Staff has indicated that it will challenge the Company's request for approval of a revenue requirement higher than was reflected in the Company's prefiled direct case in April 2005, but Staff has not yet presented any argument or legal authority in support of this proposition. The Company will respond in its reply brief.

X. CONCLUSION

144. For the reasons set forth above and in the evidence that is before the Commission in this case, the Company respectfully requests that the Commission issue an order approving its request for general rate relief.

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[334] Exh. No. 61C 19:10 – 27:8 (Markell); Exh. No. 66C 13:1 – 17:11 (Markell); Exh. No. 237C 8:8-17 (Story).
[335] Exh. No. 421 13:13 -- 14:11 (Russell).
[336] Exh. No. 421 14:15 – 15:2 (Russell); Exh. No. 66C 15:18-22 (Markell).
[337] Exh. No. 237C 8:11-15 (Story).

DATED this 18th day of January, 2005.

Respectfully submitted

PERKINS COIE LLP

By ______________________________

Kirstin S. Dodge, WSBA #22039
Jason Kuzma, WSBA #31830
Attorneys for Puget Sound Energy, Inc.

Appendix A

APPENDIX A

PSE's Requested Capital Structure and Cost of Capital

Capital Structure Re Capital Structure and Cost of Capital				
Ln #	**Item**	**Capital Structure**	**Embedded Cost**	**Rate of Return**
1	Debt			
a	Long-Term Debt	45.59%	6.88%	3.14%
b	Short-Term Debt	3.09%	4.81%	0.15%
2	Trust Preferred Stock	6.28%	8.60%	0.54%
3	Preferred Stock	0.04%	8.51%	0.00%
4	Common Equity	45.00%	11.75%	5.29%
5	Total Capital	100.00%		**9.12%**

Appendix B – Electric

Docket Numbers UG-040640 et. al
Exhibit No. (JHS-E8)
Summary

PUGET SOUND ENERGY-ELECTRIC
RESULTS OF OPERATIONS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.		ACTUAL RESULTS OF OPERATIONS	CONSERVATION TRUST	ACTUAL RESULTS OF OPERATION W/ CONSERVATION TRUST	TOTAL ADJUSTMENTS	ADJUSTED RESULTS OF OPERATIONS	REVENUE REQUIREMENT DEFICIENCY	AFTER RATE INCREASE
1	OPERATING REVENUES:							
2	SALES TO CUSTOMERS	$ 1,250,593,645	$ 11,716,081	$ 1,262,309,726	$ 152,515,852	$ 1,414,825,578	$ 99,832,183	$ 1,514,657,761
3	SALES FROM RESALE-FIRM	364,717		364,717	92,726	457,443	31,885	489,328
4	SALES TO OTHER UTILITIES	199,186,464		199,186,464	(171,647,821)	27,538,643		27,538,643
5	OTHER OPERATING REVENUES	45,262,737		45,262,737	(12,609,942)	32,652,795	93,378	32,746,173
6	TOTAL OPERATING REVENUES	1,495,407,563	11,716,081	1,507,123,644	(31,649,184)	1,475,474,459	99,957,446	1,575,431,905
7								
8	OPERATING REVENUE DEDUCTIONS:							
9								
10	POWER COSTS:							
11	FUEL	$ 64,236,514	$ -	$ 64,236,514	$ (90,698,650)	$ (26,462,136)	$ -	$ (26,462,136)
12	PURCHASED AND INTERCHANGED	769,384,600		769,384,600	(10,583,873)	758,800,727		758,800,727
13	WHEELING	39,868,912		39,868,912	4,363,075	44,231,986		44,231,986
14	RESIDENTIAL EXCHANGE	(172,382,420)		(172,382,420)	172,382,420	-		-
15	TOTAL PRODUCTION EXPENSES	701,107,606	-	701,107,606	75,462,972	776,570,577	-	776,570,577
16								
17	OTHER POWER SUPPLY EXPENSES	$ 46,852,153	$ -	$ 46,852,153	$ 5,724,178	$ 52,576,330	$ -	$ 52,576,330
18	TRANSMISSION EXPENSE	3,409,865		3,409,865	196,604	3,606,469		3,606,469
19	DISTRIBUTION EXPENSE	58,327,849		58,327,849	2,347,845	60,675,694		60,675,694
20	CUSTOMER ACCOUNT EXPENSES	34,589,847		34,589,847	42,677	34,632,524		34,632,524
21	CUSTOMER SERVICE EXPENSES	8,700,615		8,700,615	(5,754,231)	2,946,384		2,946,384
22	CONSERVATION AMORTIZATION	29,421,865	10,967,322	40,389,187	(40,290,817)	98,370		98,370
23	ADMIN & GENERAL EXPENSE	59,296,783		59,296,783	12,273,902	71,570,684	640,527	72,211,212
24	DEPRECIATION	124,154,290		124,154,290	2,336,102	126,490,392		126,490,392
25	AMORTIZATION	24,086,070		24,086,070	(1,239,405)	22,846,665		22,846,665
26	AMORTIZ OF PROPERTY GAIN/LOSS	6,000,000		6,000,000	1,475,555	7,475,555		7,475,555
27	OTHER OPERATING EXPENSES	(3,438,725)		(3,438,725)	3,634,375	195,650		195,650
28	TAXES OTHER THAN F.I.T.	131,930,399		131,930,399	(33,242,443)	98,687,956	3,853,899	102,541,855
29	FEDERAL INCOME TAXES	(5,764,878)		(5,764,878)	25,283,815	19,518,937	33,412,056	52,930,992
30	DEFERRED INCOME TAXES	57,844,151		57,844,151	(30,411,536)	27,432,615		27,432,615
31	TOTAL OPERATING REV. DEDUCT.	$ 1,276,517,888	$ 10,967,322	$ 1,287,485,210	$ 17,839,591	$ 1,305,324,801	$ 37,906,482	$ 1,343,231,283
32								
33	NET OPERATING INCOME	$ 218,889,675	$ 748,759	$ 219,638,434	$ (49,488,775)	$ 170,149,659	$ 62,050,964	$ 232,200,622
34								
35	RATE BASE	$ 2,516,697,113	$ -	$ 2,516,697,113	$ 29,362,338	$ 2,546,059,451	$ -	$ 2,546,059,451
36								
37	RATE OF RETURN	8.70%		8.73%		6.68%		9.12%
38								
39	RATE BASE:							
40	UTILITY PLANT IN SERVICE			$ 2,578,449,579	$ 27,246,325	$ 2,605,695,904		
41	DEFERRED DEBITS			334,433,269	9,027,521	343,460,790		
42	DEFERRED TAXES incl oh study			(390,406,512)	4,658,357	(385,748,155)		
43	CONSERVATION TRUST			11,569,864	(11,569,864)	(0)		
44	ALLOWANCE FOR WORKING CAPITAL			15,068,558	-	15,068,558		
45	OTHER			(32,417,645)	-	(32,417,645)		
46	TOTAL RATE BASE			$ 2,516,697,113	$ 29,362,338	$ 2,546,059,451		

PUGET SOUND ENERGY-ELECTRIC
STATEMENT OF OPERATING INCOME AND ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
RESTATING AND PRO FORMA ADJUSTMENTS

LINE NO.		ACTUAL RESULTS OF OPERATIONS WITH CONSERVATION TRUST	TEMPERATURE NORMALIZATION 2.01	GENERAL REVENUES 2.02	POWER COSTS 2.03	SALES FOR RESALE - SEC 2.04	FEDERAL INCOME TAX 2.05	TAX BENEFIT OF PRO FORMA INTEREST 2.06	DEPRECIATION/ AMORTIZATION 2.07
1	OPERATING REVENUES								
2	SALES TO CUSTOMERS	$ 1,262,309,726	$ 7,045,746	$ 145,470,106	$ -	$ -	$ -	$ -	$ -
3	SALES FROM RESALE-FIRM	364,717	1,194	91,532					
4	SALES TO OTHER UTILITIES	199,186,464				(171,647,821)			
5	OTHER OPERATING REVENUES	45,262,737		1,136,399	(9,704,193)	(3,329,377)			
6	TOTAL OPERATING REVENUES	$ 1,507,123,644	$ 7,046,940	$ 146,698,037	$ (9,704,193)	$ (174,977,198)	$ -	$ -	$ -
7									
8	OPERATING REVENUE DEDUCTIONS:								
9									
10	POWER COSTS:								
11	FUEL	$ 64,236,514	$ -	$ -	$ (90,698,650)	$ -	$ -	$ -	$ -
12	PURCHASED AND INTERCHANGED	769,384,600			(10,583,873)				
13	WHEELING	39,868,912			4,363,075				
14	RESIDENTIAL EXCHANGE	(172,382,420)			172,382,420				
15	TOTAL PRODUCTION EXPENSES	$ 701,107,606	$ -	$ -	$ 75,462,972	$ -	$ -	$ -	$ -
16									
17	OTHER POWER SUPPLY EXPENSES	$ 46,852,153	$ -	$ -	$ 5,194,506	$ -	$ -	$ -	$ -
18	TRANSMISSION EXPENSE	3,409,865			(6,306)				
19	DISTRIBUTION EXPENSE	58,327,849							
20	CUSTOMER ACCTS EXPENSES	34,589,847	31,768	661,315					
21	CUSTOMER SERVICE EXPENSES	8,700,615							
22	CONSERVATION AMORTIZATION	40,389,187							
23	ADMIN & GENERAL EXPENSE	59,296,783	13,389	278,726					130,808
24	DEPRECIATION	124,154,290							18,811
25	AMORTIZATION	24,086,070							
26	AMORTIZ OF PROPERTY GAIN/LOSS	6,000,000							
27	OTHER OPERATING EXPENSES	(3,438,725)							
28	TAXES OTHER THAN F.I.T.	131,930,399	271,698	(34,117,687)		(128,365)			
29	FEDERAL INCOME TAXES	(5,764,878)	2,355,530	62,956,489	(31,624,378)	(61,197,091)	35,362,248	9,337,425	(52,367)
30	DEFERRED INCOME TAXES	57,844,151					(30,710,901)		
31	TOTAL OPERATING REV. DEDUCT.	$ 1,287,485,210	$ 2,672,385	$ 29,778,844	$ 49,026,794	$ (61,325,456)	$ 4,651,347	$ 9,337,425	$ 97,252
32									
33	NET OPERATING INCOME	$ 219,638,434	$ 4,374,555	$ 116,919,193	$ (58,730,987)	$ (113,651,741)	$ (4,651,347)	$ (9,337,425)	$ (97,252)
34									
35	RATE BASE	$ 2,516,697,113							$ (74,810)
36									
37	RATE OF RETURN	8.73%							
38									
39	RATE BASE:								
40	UTILITY PLANT IN SERVICE	$ 2,578,449,579	$ -	$ -	$ -	$ -	$ -	$ -	$ (65,404)
41	DEFERRED DEBITS	334,433,269							(9,406)
42	DEFERRED TAXES	(390,406,512)							
43	CONSERVATION TRUST	11,569,864							
44	ALLOWANCE FOR WORKING CAPITAL	15,068,558							
45	OTHER	(32,417,645)							
46	TOTAL RATE BASE	$ 2,516,697,113	$ -	$ -	$ -	$ -	$ -	$ -	$ (74,810)

PUGET SOUND ENERGY-ELECTRIC
STATEMENT OF OPERATING INCOME AND ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
RESTATING AND PRO FORMA ADJUSTMENTS

LINE NO.		CONSERVATION 2.08	BAD DEBTS 2.09	MISCELLANEOUS OPERATING EXPENSE 2.10	PROPERTY TAXES 2.11	WHITE RIVER RELIC/PLANT COSTS 2.12	FILING FEE 2.13	D&O INSURANCE 2.14	MONTANA ENERGY TAX 2.15
1	OPERATING REVENUES								
2	SALES TO CUSTOMERS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	SALES FROM RESALE-FIRM								
4	SALES TO OTHER UTILITIES								
5	OTHER OPERATING REVENUES			(712,770)					
6	TOTAL OPERATING REVENUES	$ -	$ -	$ (712,770)	$ -	$ -	$ -	$ -	$ -
7									
8	OPERATING REVENUE DEDUCTIONS:								
9									
10	POWER COSTS:								
11	FUEL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	PURCHASED AND INTERCHANGED								
13	WHEELING								
14	RESIDENTIAL EXCHANGE								
15	TOTAL PRODUCTION EXPENSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16									
17	OTHER POWER SUPPLY EXPENSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	TRANSMISSION EXPENSE		-						
19	DISTRIBUTION EXPENSE		-	2,000,000					
20	CUSTOMER ACCTS EXPENSES		(1,478,697)						
21	CUSTOMER SERVICE EXPENSES								
22	CONSERVATION AMORTIZATION	(40,290,817)							
23	ADMIN & GENERAL EXPENSE			(273,367)			220,827	(7,961)	
24	DEPRECIATION					(1,381,963)			
25	AMORTIZATION					1,494,702			
26	AMORTIZ OF PROPERTY GAIN/LOSS								
27	OTHER OPERATING EXPENSES								
28	TAXES OTHER THAN F.I.T.			(19,136)	(2,584,327)				166,039
29	FEDERAL INCOME TAXES	14,101,786	517,544	(847,094)	904,514	(39,459)	(77,289)	2,786	(58,114)
30	DEFERRED INCOME TAXES								
31	TOTAL OPERATING REV. DEDUCT.	$ (26,189,031)	$ (961,153)	$ 860,403	$ (1,679,813)	$ 73,280	$ 143,538	$ (5,175)	$ 107,925
32									
33	NET OPERATING INCOME	$ 26,189,031	$ 961,153	$ (1,573,174)	$ 1,679,813	$ (73,280)	$ (143,538)	$ 5,175	$ (107,925)
34									
35	RATE BASE	$ (11,569,864)		$ 1,711,055		$ 19,837,623			
36									
37	RATE OF RETURN								
38									
39	RATE BASE:								
40	UTILITY PLANT IN SERVICE	$ -	$ -	$ 1,711,055	$ -	$ (43,511,694)	$ -	$ -	$ -
41	DEFERRED DEBITS					63,291,415			
42	DEFERRED TAXES					57,902			
43	CONSERVATION TRUST	(11,569,864)							
44	ALLOWANCE FOR WORKING CAPITAL								
45	OTHER								
46	TOTAL RATE BASE	$ (11,569,864)	$ -	$ 1,711,055	$ -	$ 19,837,623	$ -	$ -	$ -

PUGET SOUND ENERGY-ELECTRIC
STATEMENT OF OPERATING INCOME AND ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
RESTATING AND PRO FORMA ADJUSTMENTS

LINE NO.		INTEREST ON CUST DEPOSITS 2.16	SFAS 133 2.17	RATE CASE EXPENSES 2.18	PROPERTY SALES 2.19	PROPERTY & LIABILITY INS 2.20	PENSION PLAN 2.21	WAGE INCREASE 2.22	INVESTMENT PLAN 2.23	EMPLOYEE INSURANCE 2.24
1	OPERATING REVENUES									
2	SALES TO CUSTOMERS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	SALES FROM RESALE-FIRM									
4	SALES TO OTHER UTILITIES									
5	OTHER OPERATING REVENUES									
6	TOTAL OPERATING REVENUES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7										
8	OPERATING REVENUE DEDUCTIONS:									
9										
10	POWER COSTS:									
11	FUEL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	PURCHASED AND INTERCHANGED									
13	WHEELING									
14	RESIDENTIAL EXCHANGE									
15	TOTAL PRODUCTION EXPENSES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16										
17	OTHER POWER SUPPLY EXPENSES	$ -	$ -	$ -	$ -	$ -	$ -	$ 536,545	$ -	$ -
18	TRANSMISSION EXPENSE							74,324		
19	DISTRIBUTION EXPENSE							1,205,899		
20	CUSTOMER ACCTS EXPENSES	151,631						676,660		
21	CUSTOMER SERVICE EXPENSES							94,774		
22	CONSERVATION AMORTIZATION									
23	ADMIN & GENERAL EXPENSE			$243,063		494,792	8,562,018	953,746	160,316	1,269,733
24	DEPRECIATION									
25	AMORTIZATION									
26	AMORTIZ OF PROPERTY GAIN/LOSS									
27	OTHER OPERATING EXPENSES		(855,328)		4,489,703					
28	TAXES OTHER THAN F.I.T.							319,356		
29	FEDERAL INCOME TAXES			$ (85,072)	(1,571,396)	(173,177)	(2,996,706)	(1,351,456)	(56,111)	(444,407)
30	DEFERRED INCOME TAXES		299,365							
31	TOTAL OPERATING REV. DEDUCT.	$ 151,631	$ (555,963)	$ 157,991	$ 2,918,307	$ 321,615	$ 5,565,312	$ 2,509,848	$ 104,205	$ 825,326
32										
33	NET OPERATING INCOME	$ (151,631)	$ 555,963	$ (157,991)	$ (2,918,307)	$ (321,615)	$ (5,565,312)	$ (2,509,848)	$ (104,205)	$ (825,326)
34										
35	RATE BASE									
36										
37	RATE OF RETURN									
38										
39	RATE BASE:									
40	UTILITY PLANT IN SERVICE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	DEFERRED DEBITS									
42	DEFERRED TAXES									
43	CONSERVATION TRUST									
44	ALLOWANCE FOR WORKING CAPITAL									
45	OTHER									
46	TOTAL RATE BASE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

PUGET SOUND ENERGY-ELECTRIC
STATEMENT OF OPERATING INCOME AND ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
RESTATING AND PRO FORMA ADJUSTMENTS

LINE NO.		MONTANA CORP LICENSE TAX 2.25	STORM DAMAGE 2.26	REDACTED	LOW INCOME AMORTIZATION 2.28	REGULATORY ASSETS 2.29	PRODUCTION ADJUSTMENT 2.30	TOTAL ADJUSTMENTS	ADJUSTED RESULTS OF OPERATIONS
1	OPERATING REVENUES								
2	SALES TO CUSTOMERS	$ -	$ -		$ -	$ -	$ -	$ 152,515,852	$ 1,414,825,578
3	SALES FROM RESALE-FIRM							92,726	457,443
4	SALES TO OTHER UTILITIES							(171,647,821)	27,538,643
5	OTHER OPERATING REVENUES							(12,609,942)	32,652,795
6	TOTAL OPERATING REVENUES	$ -	$ -		$ -	$ -	$ -	$ (31,649,184)	$ 1,475,474,459
7									
8	OPERATING REVENUE DEDUCTIONS:								
9									
10	POWER COSTS:								
11	FUEL	$ -	$ -		$ -	$ -	$ -	$ (90,698,650)	$ (26,462,136)
12	PURCHASED AND INTERCHANGED							(10,583,873)	758,800,727
13	WHEELING							4,363,075	44,231,986
14	RESIDENTIAL EXCHANGE							172,382,420	-
15	TOTAL PRODUCTION EXPENSES	$ -	$ -		$ -	$ -	$ -	$ 75,462,972	$ 776,570,577
16									
17	OTHER POWER SUPPLY EXPENSES	$ -	$ -		$ -	$ -	$ (6,873)	$ 5,724,178	$ 52,576,330
18	TRANSMISSION EXPENSE		128,586					196,604	3,606,469
19	DISTRIBUTION EXPENSE		(858,054)					2,347,845	60,675,694
20	CUSTOMER ACCTS EXPENSES							42,677	34,632,524
21	CUSTOMER SERVICE EXPENSES				(5,849,005)			(5,754,231)	2,946,384
22	CONSERVATION AMORTIZATION							(40,290,817)	98,370
23	ADMIN & GENERAL EXPENSE						(50,813)	12,273,902	71,570,684
24	DEPRECIATION						(484,478)	2,336,102	126,490,392
25	AMORTIZATION		165,768				(42,021)	(1,239,405)	22,846,665
26	AMORTIZ OF PROPERTY GAIN/LOSS						(19,147)	1,475,555	7,475,555
27	OTHER OPERATING EXPENSES							3,634,375	195,650
28	TAXES OTHER THAN F.I.T.	1,973,934					(154,356)	(33,242,443)	98,687,956
29	FEDERAL INCOME TAXES	(690,877)	197,295		2,047,152		211,400	25,283,815	19,518,937
30	DEFERRED INCOME TAXES							(30,411,536)	27,432,615
31	TOTAL OPERATING REV. DEDUCT.	$ 1,283,057	$ (366,405)		$ (3,801,853)	$ -	$ (546,289)	$ 17,839,591	$ 1,305,324,801
32									
33	NET OPERATING INCOME	$ (1,283,057)	$ 366,405		$ 3,801,853	$ -	$ 546,289	$ (49,488,775)	$ 170,149,659
34									
35	RATE BASE				$ -	$ (46,237,863)	$ (9,748,332)	$ 29,362,338	$ 2,546,059,451
36									
37	RATE OF RETURN								6.68%
38									
39	RATE BASE:								
40	UTILITY PLANT IN SERVICE	$ -	$ -		$ -	$	$ (7,770,271)	$ 27,246,325	$ 2,605,695,904
41	DEFERRED DEBITS					(50,464,932)	(3,789,556)	9,027,521	343,460,790
42	DEFERRED TAXES					4,227,069	1,811,495	4,658,357	(385,748,155)
43	CONSERVATION TRUST							(11,569,864)	(0)
44	ALLOWANCE FOR WORKING CAPITAL							-	15,068,558
45	OTHER							-	(32,417,645)
46	TOTAL RATE BASE	$ -	$ -		$ -	$ (46,237,863)	$ (9,748,332)	$ 29,362,338	$ 2,546,059,451

Confidential Per Protective Order in WUTC Docket Nos. UG-040640 et al.

(Note 1) CONFIDENTIAL per Protective Order in UE-040640 and CONFIDENTIAL per WAC 480-07-160

PUGET SOUND ENERGY-ELECTRIC
TEMPERATURE NORMALIZATION
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION						
1	TEMPERATURE NORMALIZATION ADJUSTMENT:						
2			ACTUAL	TEMP ADJ	MWH	ADJ FOR LOSSES	
3			GPI MWH	GPI MWH	CHANGE	6.40%	
4		Oct-02	1,691,158	1,670,669	(20,489)	(19,178)	
5		Nov-02	1,807,647	1,841,715	34,068	31,887	
6		Dec-02	2,061,746	2,120,555	58,809	55,046	
7		Jan-03	1,979,614	2,101,564	121,950	114,145	
8		Feb-03	1,848,298	1,813,468	(34,830)	(32,601)	
9		Mar-03	1,877,283	1,893,108	15,825	14,812	
10		Apr-03	1,691,863	1,670,087	(21,776)	(20,383)	
11		May-03	1,585,662	1,575,964	(9,698)	(9,077)	
12		Jun-03	1,490,550	1,474,297	(16,253)	(15,213)	
13		Jul-03	1,568,794	1,553,446	(15,348)	(14,366)	
14		Aug-03	1,532,398	1,525,817	(6,581)	(6,160)	
15		Sep-03	1,506,449	1,498,678	(7,771)	(7,274)	
16			20,641,463	20,739,368	97,905	91,638	
17							
18	REVENUE ADJUSTMENT:	Schedule 7				$ 6,876,128	
19		Schedule 24				58,139	
20		Schedule 25				(145,160)	
21		Schedule 26				(168,308)	
22		Schedule 29				16,067	
23		Schedule 31				(165,176)	
24		Schedule 35				-	
25		Schedule 43				574,056	
26		Firm Resale				1,194	
27	INCREASE (DECREASE) SALES TO CUSTOMERS						$ 7,046,940
28							
29	UNCOLLECTIBLES @				0.0045080	$ 31,768	
30	ANNUAL FILING FEE @				0.0019000	13,389	
31	INCREASE (DECREASE) EXPENSES						45,157
32							
33	STATE UTILITY TAX @				0.0385554	$ 271,698	
34	INCREASE (DECREASE) TAXES OTHER						271,698
35							
36	INCREASE (DECREASE) INCOME						6,730,085
37							
38	INCREASE (DECREASE) FIT @				35%		2,355,530
39	INCREASE (DECREASE) NOI						$ 4,374,555

PUGET SOUND ENERGY-ELECTRIC
GENERAL REVENUES ADJUSTMENT
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		ADJUSTMENT	
1	**SALES TO CUSTOMERS:**			
2	RESTATING ADJUSTMENTS:			
3	ADD BACK SCHEDULE 94 RESIDENTIAL/FARM CREDIT		$ 180,281,489	
4	REMOVE MUNICIPAL TAXES		(40,996,559)	
5	REMOVE SCHEDULE 120 CONSERVATION RIDER REVENUE		(26,692,602)	
6	ADD BACK CENTRALIA CREDIT		7,653	
7	OUT OF PERIOD CHARGES		(3,570,280)	
8	LOW INCOME RATE CHANGE		(3,830,521)	
9	MISCELLANEOUS RESTATING ADJUSTMENTS - SALES TO CUSTOMERS		(785,533)	
10	MISCELLANEOUS RESTATING ADJUSTMENTS - SALES FROM RESALE-FIRM		(14,782)	
11	SUBTOTAL RESTATING ADJUSTMENTS		104,398,865	
12				
13	PROFORMA ADJUSTMENTS:			
14	PCORC PROFORMA INCREASE DOCKET 03-1725		44,192,861	
15	PROFORMA UNBILLED REVENUE		542,641	
16	LOW INCOME REVENUE		(2,269,353)	
17	MISC. PROFORMA ADJSUTMENTS - SALES TO CUSTOMERS		(1,409,690)	
18	MISC. PROFORMA ADJSUTMENTS - SALES FROM RESALE-FIRM		106,314	
19	SUBTOTAL PROFORMA ADJUSTMENTS		41,162,773	
20				
21	TOTAL INCREASE (DECREASE) SALES TO CUSTOMERS			$ 145,561,638
22				
23	**OTHER OPERATING REVENUES:**			
24	MISCELLANEOUS CUSTOMER CHARGES		706,411	
25	MISC. PROFORMA ADJSUTMENTS - OTHER OPERATING REVENUES		429,988	
26				
27	TOTAL INCREASE (DECREASE) OTHER OPERATING REVENUE			1,136,399
28				
29	**TOTAL INCREASE (DECREASE) REVENUES**			146,698,037
30				
31	UNCOLLECTIBLES @	0.0045080	$ 661,315	
32	ANNUAL FILING FEE @	0.0019000	278,726	
33	INCREASE (DECREASE) EXPENSES			940,041
34				
31	STATE UTILITY TAX @	0.0385554	$ 5,656,001	
32	MUNICIPAL TAX EXPENSED		(39,773,688)	
33	INCREASE (DECREASE) TAXES OTHER			(34,117,687)
34				
35	INCREASE (DECREASE) INCOME			179,875,682
36				
37	INCREASE (DECREASE) FIT @	35%		62,956,489
38	INCREASE (DECREASE) NOI			$ 116,919,193

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PUGET SOUND ENERGY-ELECTRIC
POWER COSTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	ACTUAL	PROFORMA	INCREASE (DECREASE)
1	PRODUCTION EXPENSES:			
2	FUEL	$ 64,236,514	$ 146,121,367	$ 81,884,853
3	PURCHASED AND INTERCHANGED	769,384,600	596,801,097	(172,583,503)
3a	TENASKA DISALLOWANCE	-	(10,583,873)	(10,583,873)
4				
5	WHEELING	39,868,912	44,231,987	4,363,075
6	HYDRO AND OTHER POWER	46,852,153	52,046,659	5,194,506
7	TRANS. EXP. INCL. 500KV O&M	492,266	485,960	(6,306)
8	SALES FOR RESALE	(199,186,464)	(27,538,643)	171,647,821
9	PURCHASES/SALES OF NON-CORE GAS	(9,704,193)	-	9,704,193
10	WHEELING FOR OTHERS	(12,727,829)	(9,398,452)	3,329,377
11	SUBTOTAL	$ 699,215,959	$ 792,166,102	$ 92,950,143
12				
13	LESS: SALES FOR RESALE	199,186,464	27,538,643	(171,647,821)
14	LESS: WHEELING FOR OTHERS	12,727,829	9,398,452	(3,329,377)
15	SCH. 94 - RES./FARM CREDIT	(172,382,420)	-	172,382,420
16	TOTAL	$ 738,747,832	$ 829,103,197	$ 90,355,364
17	TRANS. EXP. INCL. 500KV O&M	(492,266)		
18	PURCHASES/SALES OF NON-CORE GAS	9,704,193		
19	POWER COSTS PER G/L	$ 747,959,759		
20	INCREASE(DECREASE) INCOME			$ (90,355,364)
21				
22	INCREASE(DECREASE) FIT @	35%		(31,624,378)
23	INCREASE(DECREASE) NOI			$ (58,730,987)

PUGET SOUND ENERGY-ELECTRIC
SALES FOR RESALE - SECONDARY
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT	ADJUSTMENT
1	PROFORMA SALES FOR RESALE - OTHER UTILITIES		$ 27,538,643	
2	ACTUAL SALES FOR RESALE - OTHER UTIL.		199,186,464	
3	INCREASE (DECREASE) REVENUES - OTHER UTILITIES			$ (171,647,821)
4				
5	PROFORMA REVENUES - WHEELING FOR OTHERS		$ 9,398,452	
6	ACTUAL REVENUES - WHEELING FOR OTHERS		12,727,829	
7	INCREASE (DECREASE) OTHER OPERATING REVENUES			(3,329,377)
8	INCREASE (DECREASE) REVENUE			$ (174,977,198)
9				
10	STATE UTILITY TAX			
11	(APPLICABLE TO LINE 7)	0.0385554	(128,365)	
12	INCREASE (DECREASE) STATE UTILITY TAX			(128,365)
13	INCREASE (DECREASE) INCOME			$ (174,848,832)
14				
15	INCREASE (DECREASE) FIT @		35%	(61,197,091)
16	INCREASE (DECREASE) NOI			$ (113,651,741)

PUGET SOUND ENERGY-ELECTRIC
FEDERAL INCOME TAX
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			AMOUNT
1	TAXABLE INCOME		$	84,563,914
2				
3	FEDERAL INCOME TAX @	35%		29,597,370
4	CURRENTLY PAYABLE		$	29,597,370
5				
6	DEFERRED FIT - DEBIT		$	41,384,000
7	DEFERRED FIT - CREDIT			(14,250,750)
8	DEFERRED FIT - INV TAX CREDIT, NET OF AMORT.			-
9	TOTAL RESTATED FIT		$	56,730,620
10				
11	FIT PER BOOKS:			
12	CURRENTLY PAYABLE	$ (5,764,878)		
13	DEFERRED FIT - DEBIT	78,533,358		
14	DEFERRED FIT - CREDIT	(20,689,207)		
15	DEFERRED FIT - INV TAX CREDIT, NET OF AMORT.	-		
16	TOTAL CHARGED TO EXPENSE		$	52,079,273
17				
18	INCREASE(DECREASE) FIT			35,362,248
19	INCREASE(DECREASE) DEFERRED FIT			(30,710,901)
20	INCREASE(DECREASE) NOI		$	(4,651,347)

PUGET SOUND ENERGY-ELECTRIC
TAX BENEFIT OF PRO FORMA INTEREST
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION				AMOUNT
1	RATE BASE	$	2,546,059,451		
2	DEDUCTIBLE CWIP		63,264,591		
3	NET RATE BASE	$	2,609,324,042		
4					
5	WEIGHTED COST OF DEBT		3.83%		
6	PROFORMA INTEREST			$	99,891,098
7					
8	INTEREST EXPENSE ITEMS PER BOOKS:				
9	INTEREST ON LONG TERM DEBT	$	119,754,211		
10	AMORTIZATION OF DEBT DISCOUNT				
11	AND EXPENSE, NET OF PREMIUMS		2,967,877		
12	CONSERVATION TRUST INTEREST		865,394		
13	OTHER INTEREST EXPENSE		3,133,604		
14	LESS: INTEREST ON CUSTOMER DEPOSITS		(151,631)		
15	CHARGED TO EXPENSE IN TEST YEAR				126,569,455
16					
17	INCREASE (DECREASE) INCOME			$	26,678,357
18					
19	INCREASE (DECREASE) FIT @		35%		9,337,425
20	INCREASE (DECREASE) NOI			$	(9,337,425)

PUGET SOUND ENERGY-ELECTRIC
DEPRECIATION/AMORTIZATION
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	TEST YEAR	RESTATED		ADJUSTMENT
1	NET OPERATING INCOME:				
2					
3	DEPRECIATION EXPENSE (FERC 403)	$ 124,127,498	$ 124,258,306	$	130,808
4					
5	AMORTIZATION EXPENSE:				
6	WUTC AFUDC PLANT ACQUISITION ADJUSTMENT	1,160,838	1,179,649		18,811
7					
8	INCREASE (DECREASE) NET OPERATING INCOME	125,288,336	125,437,955	$	(149,619)
9					
10	INCREASE (DECREASE) FIT @		35%		(52,367)
11	INCREASE (DECREASE) NOI			$	(97,252)
12					
13					
14					
15	ADJUST RATE BASE FOR LINE 8				
16	UTILITY PLANT IN SERVICE (50% x LINE 3)			$	(65,404)
17	DEFERRED DEBITS (50% X LINE 6)				(9,406)
18	TOTAL ADJUSTMENT TO RATEBASE		50%		(74,810)

PUGET SOUND ENERGY-ELECTRIC
CONSERVATION
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT	ADJUSTMENT
1	CONSERVATION RIDER AMORTIZATION			
2	ACTUAL CONSERVATION RIDER AMORTIZATION		$ 26,807,031	
3	RESTATED CONSERVATION RIDER AMORTIZATION		-	
4	INCREASE (DECREASE) EXPENSE		(26,807,031)	
5	INCREASE (DECREASE) OPERATING INCOME			$ 26,807,031
6				
7	PROFORMA			
8	95 CONSERVATION TRUST AMORTIZATION			
9	ACTUAL 95 CONSERVATION TRUST AMORTIZATION		14,776,806	
10	PROFORMA 95 CONSERVATION TRUST AMORTIZATION		-	
11	INCREASE (DECREASE) EXPENSE		(14,776,806)	
12	INCREASE (DECREASE) OPERATING INCOME			14,776,806
13				
14	ONE TIME ADJUSTMENTS IN ACCOUNT 18230621			
15	SCH128 OVER-COLLECTION TRANSFER		(643,539)	
16	CENTRALIA FUEL TAX REFUND FROM PACIFICORP		(420,042)	
17	TRANSALTA (SCRUBBER ESC)		(229,439)	
18	INCREASE (DECREASE) EXPENSE		1,293,020	
19	INCREASE (DECREASE) OPERATING INCOME			(1,293,020)
20				
21	TOTAL AMORTIZATION			$ 40,290,817
22				
23	INCREASE (DECREASE) FIT	35%		$ 14,101,786
24				
25	INCREASE (DECREASE) NOI			$ 26,189,031
26				
27	**RATE BASE ADJUSTMENTS:**			
28	95 CONSERVATION TRUST			(11,569,864)
29	RATE BASE ADJUSTMENT			$ (11,569,864)

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PUGET SOUND ENERGY-ELECTRIC
BAD DEBTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	YEAR	NET WRITEOFF'S	GROSS REVENUES	SALES FOR RESALE OTHER	SALES FOR RESALE FIRM	NET REVENUES	PERCENT WRITEOFF'S TO REVENUE
1	12 MOS ENDED 09/30/1999	$ 4,517,174	$ 1,527,267,919	$ 296,742,686	$ 5,478,269	$ 1,225,046,964	0.3687347%
2	12 MOS ENDED 09/30/2001	$ 7,000,498	$ 2,460,850,948	$ 955,657,851	$ 24,744,688	$ 1,480,448,409	0.4728634%
3	12 MOS ENDED 09/30/2002	$ 6,321,472	$ 1,346,477,688	$ 93,764,521	$ 945,576	$ 1,251,767,591	0.5050036%
4	3-Yr Average of Net Write Off Rate						**0.4507950%**
5							
6	Test Period Revenues		$ 1,495,407,563	$ 199,186,464	$ 364,717	$ 1,295,856,382	
7							
8	PROFORMA BAD DEBT RATE					0.4507950%	
9	PROFORMA BAD DEBTS					$ 5,841,656	
10							
11	UNCOLLECTIBLES CHARGED TO EXPENSE IN TEST YEAR					7,320,353	
12	INCREASE (DECREASE) EXPENSE						$ (1,478,697)
13							
14	INCREASE (DECREASE) FIT					35%	517,544
15	INCREASE (DECREASE) NOI						**$ 961,153**

PUGET SOUND ENERGY-ELECTRIC
MISCELLANEOUS OPERATING EXPENSE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	ACTUAL	PROFORMA RESTATED	ADJUSTMENT
1	OPERATING EXPENSES (RESTATED)			
2	INCENTIVE/MERIT PAY	$ 2,479,895	$ 2,206,528	$ (273,367)
3	PAYROLL TAXES ASSOC WITH MERIT PAY	173,593	154,457	(19,136)
4	OPERATING EXPENSES (PROFORMA)			
5	TREE WATCH	-	2,000,000	2,000,000
6	REDUCE STEAM SALES TO GP	(1,558,715)	(845,945)	712,770
7	INCREASE (DECREASE) IN EXPENSE	$ 1,094,772	$ 3,515,040	$ 2,420,268
8				
9	INCREASE(DECREASE) INCOME			(2,420,268)
10	INCREASE(DECREASE) FIT @		35%	(847,094)
11				
12	INCREASE(DECREASE) NOI			$ (1,573,174)
13				
14	RATEBASE			
15	FUTURE USE ADJUSTMENT			33,275
16	CWIP "IN SERVICE" BUT NOT TRANSFERRED TO PLANT			1,677,780
17				
18	TOTAL ADJUSTMENT TO RATEBASE			$ 1,711,055

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PUGET SOUND ENERGY-ELECTRIC
PROPERTY TAXES
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	WASHINGTON	MONTANA	OREGON	TOTAL
1	RESTATED PROPERTY TAX	$ 23,275,330	$ 8,987,002	$ 981,652	$ 33,243,984
2	CHARGED TO EXPENSE IN TY	23,055,301	9,387,665	829,823	33,272,789
3	INCREASE(DECREASE) INCOME	$ (220,029)	$ 400,663	$ (151,829)	$ 28,805
4					
5	1995-2001 BACK TAX PAYMENT MADE IN TEST YEAR			$ 3,833,282	
6	RATE YEAR AMOUNT (BASE ON 3 YEAR AVERAGE)			$ (1,277,761)	
7	INCREASE(DECREASE) INCOME				$ 2,555,521
8					
9	TOTAL INCREASE(DECREASE) INCOME				$ 2,584,327
10	INCREASE(DECREASE) FIT @			35%	904,514
11					
12	INCREASE(DECREASE) NOI				$ 1,679,813

PUGET SOUND ENERGY-ELECTRIC
WHITE RIVER RELICENSING AND PLANT COSTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	TEST YEAR	PROFORMA	ADJUSTMENT
1	**EFFECT ON OVERALL OPERATING EXPENSES:**			
2	ADJUSTMENT TO DEPRECIATION EXPENSE (FERC 403):			
3	RELICENSING COSTS	$ -	$ -	$ -
4	PLANT COSTS	1,381,963	-	(1,381,963)
6	TOTAL OPERATING EXPENSE (FERC 403)	$ 1,381,963	$ -	(1,381,963)
7				
8	ADJUSTMENT TO AMORTIZATION EXPENSE (FERC 407):			
9	RELICENSING COSTS	$ -	$ -	$ -
10	PLANT COSTS	-	1,494,702	1,494,702
12	TOTAL OPERATING EXPENSE (FERC 407)	$ -	$ 1,494,702	1,494,702
13				
14	INCREASE (DECREASE) INCOME			(112,739)
15				
16	INCREASE (DECREASE) FIT @		35%	(39,459)
17	INCREASE (DECREASE) NOI			$ (73,280)
18				
19	**EFFECT ON OVERALL RATEBASE:**			
20	**ADJUSTMENT TO PRODUCTION RATE BASE:**			
21	PLANT COSTS			
22	GROSS PLANT	$ 61,716,085	$ -	$ (61,716,085)
23	ACCUMULATED DEPREC / AMORT	(18,204,391)	-	18,204,391
24	DEFERRED FIT	(4,105,474)	-	4,105,474
25	NET PLANT COSTS IN BEG PROD RB (Note 1)	$ 39,406,220	$ -	$ (39,406,220)
26				
27	**ADJUSTMENT TO REGULATORY ASSET RATE BASE:**			
28	RELICENSING COSTS			
29	DEFERRED RELICENSING COSTS:			
30	WHITE RIVER LICENSING CHARGES	$ -	$ 15,201,438	$ 15,201,438
31	WATER RIGHTS	-	-	-
32	OTHER WHITE RIVER CWIP	-	2,698,922	2,698,922
33	GROSS RELICENSING COSTS - AMA	-	17,900,360	17,900,360
34	ACCUMULATED AMORTIZATION - AMA	-	-	-
35				
36	TOTAL ADJUST TO REG ASSET RATEBASE	-	17,900,360	17,900,360
37	PLANT COSTS			
38	GROSS PLANT	-	66,660,934	66,660,934
39	ACCUMULATED DEPREC / AMORT	-	(21,269,880)	(21,269,880)
40	DEFERRED FIT	-	(4,047,572)	(4,047,572)
41	NET PLANT COSTS	-	41,343,483	41,343,483
42				
43	**EFFECT ON OVERALL RATEBASE**	$ 39,406,220	$ 59,243,843	$ 19,837,623
44				
45				
46				
47				
48				

PUGET SOUND ENERGY-ELECTRIC
FILING FEE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			AMOUNT
1	RESTATED WUTC FILING FEE		$	2,489,964
2	CHARGED TO EXPENSE FOR TEST YEAR			2,269,137
3	INCREASE(DECREASE) WUTC FILING FEE		$	220,827
4				
5	INCREASE(DECREASE) INCOME			(220,827)
6				
7	INCREASE(DECREASE) FIT @	35%		(77,289)
8	INCREASE(DECREASE) NOI		$	(143,538)

PUGET SOUND ENERGY-ELECTRIC
D&O INSURANCE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	TEST YEAR	RESTATED	ADJUSTMENT
1	D & O INS. CHG EXPENSE	$ 543,323	$ 535,361	$ (7,961)
2				
3	INC(DEC) IN EXPENSE	$ 543,323	$ 535,361	$ (7,961)
4				
5	INCREASE(DECREASE) OPERATING INCOME			7,961
6	INCREASE (DECREASE) FIT @		35%	2,786
7	INCREASE (DECREASE) NOI			$ 5,175

PUGET SOUND ENERGY-ELECTRIC
MONTANA ELECTRIC ENERGY TAX
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			AMOUNT
1	RESTATED KWH (COLSTRIP)		4,976,696,000	
2	TAX RATE		0.00035	
3				
4	RESTATED ENERGY TAX			1,741,844
5	CHARGED TO EXPENSE			1,575,805
6	INCREASE (DECREASE) INCOME			$ (166,039)
7				
8	INCREASE (DECREASE) FIT @	35%		(58,114)
9	INCREASE (DECREASE) NOI			$ (107,925)

PUGET SOUND ENERGY-ELECTRIC
INTEREST ON CUSTOMER DEPOSITS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT
1	INTEREST EXPENSE FOR TEST YEAR	$	151,631
2			
3			
4	INCREASE (DECREASE) NOI	$	(151,631)

PUGET SOUND ENERGY-ELECTRIC
SFAS 133
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.		ACTUAL	RESTATED	ADJUSTMENT
1	FAS 133 OPERATING EXPENSE	$ 855,328	$ -	$ (855,328)
2				
3	INCREASE (DECREASE) IN EXPENSE	$ 855,328	$ -	$ (855,328)
4				
5	INCREASE(DECREASE) OPERATING INCOME			855,328
6				
7	INCREASE (DECREASE) DEFERRED FIT @	35%		299,365
8				
9	INCREASE (DECREASE) NOI			$ 555,963

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PUGET SOUND ENERGY-ELECTRIC
RATE CASE EXPENSES
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			AMOUNT
1	2001 GRC EXPENSE BALANCE AS 9/30/03		$	1,843,240
2	LESS PROJECTED AMORTIZATION FROM 10/01/03-2/28/05			(1,086,963)
3	REMAINING BALANCE @ 2/28/2005			756,277
4				
5				
6				
7				
8	PROFORMA NEW RATE CASE EXPENSE:			
9	OUTSIDE SERVICE-PROFESSIONAL			766,959
10	OUTSIDE SERVICE-LEGAL			707,347
11	OTHERS			53,117
12	TOTAL PROFORMA NEW RATE CASE EXPENSE			1,527,422
13				
14	AMOUNT TO BE AMORTIZED OVER 3 YEARS		$	2,283,700
15				
16	ANNUAL AMORTIZATION			761,233
17	LESS TEST YEAR AMORTIZATION @63,939/MONTH			(767,268)
18	1/2 OF ESTIMATED PCORC EXPENSE			650,000
19	LESS PCORC AMOUNT THAT WAS COUNTED IN THE I/S			(400,902)
20				
21	INCREASE (DECREASE) EXPENSE		$	243,063
22				
24	INCREASE(DECREASE) FIT @	35%		(85,072)
25	INCREASE(DECREASE) NOI		$	(157,991)

PUGET SOUND ENERGY-ELECTRIC
PROPERTY SALES
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT
1	DEFERRED GAIN RECORDED SINCE UE-921262 @ 2/28/2005	$	(1,863,550)
2	DEFERRED LOSS RECORDED SINCE UE-921262 @ 2/28/2005		1,129,764
3	TOTAL DEFERRED NET GAIN TO AMORTIZE	$	(733,786)
4			
5	AMORTIZATION OF DEFERRED NET GAIN FOR RATE YEAR (Line 3/3years)		(244,595)
6			
7	AMORTIZATION OF DEFERRED NET GAIN FOR TEST YEAR		(4,734,298)
8			
9	INCREASE (DECREASE) EXPENSE (Line 5 + Line 7)	$	4,489,703
10			
11	INCREASE (DECREASE) FIT @ 35%		(1,571,396)
12			
13	INCREASE (DECREASE) NOI	$	(2,918,307)

PUGET SOUND ENERGY-ELECTRIC
PROPERTY & LIABILITY INSURANCE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		ACTUAL		PROFORMA		ADJUSTMENT
1	PROPERTY INSURANCE EXPENSE	$	2,081,708	$	1,835,821		(245,887)
2	LIABILITY INSURANCE EXPENSE		1,296,002		2,036,681		740,679
3	INCREASE(DECREASE) EXPENSE	$	3,377,710	$	3,872,502	$	494,792
4							
5	INCREASE(DECREASE) OPERATING INCOME						(494,792)
6	INCREASE (DECREASE) FIT @		35%				(173,177)
7	INCREASE (DECREASE) NOI					$	(321,615)

PUGET SOUND ENERGY-ELECTRIC
PENSION PLAN
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		ACTUAL		RESTATED		ADJUSTMENT
1	QUALIFIED RETIREMENT FUND	$	(6,131,331)	$	2,891,507	$	9,022,838
2	SERP PLAN		2,542,877		2,082,057	$	(460,820)
3	INCREASE(DECREASE) EXPENSE	$	(3,588,454)	$	4,973,564	$	8,562,018
4							
5	INCREASE(DECREASE) OPERATING INCOME						(8,562,018)
6	INCREASE (DECREASE) FIT @		35%				(2,996,706)
7	INCREASE (DECREASE) NOI					$	(5,565,312)

PUGET SOUND ENERGY-ELECTRIC
WAGE INCREASE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	TEST YEAR	RATE YEAR	ADJUSTMENT
1	WAGES:			
2	PRODUCTION	$ 8,370,435	$ 8,906,980	$ 536,545
3	TRANSMISSION	1,159,494	1,233,817	74,324
4	DISTRIBUTION	18,812,777	20,018,676	1,205,899
5	CUSTOMER ACCTS	10,556,324	11,232,985	676,660
6	CUSTOMER SERVICE	1,073,955	1,142,795	68,840
7	SALES	404,574	430,507	25,933
8	ADMIN. & GENERAL	14,879,040	15,832,787	953,746
9	TOTAL WAGE INCREASE	55,256,599	58,798,547	3,541,948
10				
11	PAYROLL TAXES	4,631,774	4,951,130	319,356
12	TOTAL WAGES & TAXES	59,888,373	63,749,677	3,861,304
13				
14	INCREASE (DECREASE) OPERATING INC.			$ (3,861,304)
15	INCREASE (DECREASE) FIT @ 35%			(1,351,456)
16	INCREASE (DECREASE) NOI			$ (2,509,848)

PUGET SOUND ENERGY-ELECTRIC
INVESTMENT PLAN
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT
1	MANAGEMENT (INC. EXECUTIVES)		
2	INVESTMENT PLAN APPLICABLE TO MANAGEMENT		2,593,999
3	RATE YEAR MANAGEMENT WAGE INCREASE	5.34%	138,520
4	TOTAL COMPANY CONTRIBUTION FOR MANAGEMENT		2,732,519
5			
6	UNION		
7	INVESTMENT PLAN APPLICABLE TO UNION		1,237,966
8	RATE YEAR UNION WAGE INCREASE	7.88%	97,552
9	TOTAL COMPANY CONTRIBUTION FOR UNION		1,335,518
10			
11	TOTAL		
12	TOTAL PROFORMA COSTS (LN 4 + LN 9)		4,068,036
13	PRO FORMA COSTS APPLICABLE TO OPERATIONS	67.91%	2,762,603
14	CHARGED TO EXPENSE FOR YEAR ENDED 9/30/2003		2,602,287
15	INCREASE (DECREASE) INCOME		(160,316)
16			
17	INCREASE (DECREASE) FIT @	35%	(56,111)
18	INCREASE (DECREASE) NOI		(104,205)

PUGET SOUND ENERGY-ELECTRIC
EMPLOYEE INSURANCE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			AMOUNT
1	BENEFIT CONTRIBUTION:			
2	SALARIED EMPLOYEES		$	5,186,863
3	UNION EMPLOYEES			5,502,453
4	PRO FORMA INSURANCE COSTS			10,689,316
5				
6	APPLICABLE TO OPERATIONS @	67.73%		7,239,874
7	CHARGED TO EXPENSE 09/30/03			5,970,141
8	INCREASE(DECREASE) INCOME			(1,269,733)
9				
10	INCREASE(DECREASE) FIT @	35%		(444,407)
11				
12	INCREASE(DECREASE) NOI		$	(825,326)

PUGET SOUND ENERGY-ELECTRIC
MONTANA CORPORATE LICENSE TAX
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT
1	FEDERAL CURRENT TAXABLE INCOME		$ 51,509,914
2	ADD: MONTANA CORP. LICENSE TAX DED. ON BOOKS		(1,741,728)
3	PRO FORMA INTEREST ADJUSTMENT		26,678,357
4	INCOME SUBJECT TO APPORTIONMENT		76,446,543
5			
6	MONTANA APPORTIONMENT FACTOR		4.50%
7	MONTANA TAXABLE INCOME		3,440,094
8			
9	PROFORMA MONTANA CORP. LIC. TAX	6.75%	232,206
10	CHARGED TO EXPENSE IN TEST YEAR		(1,741,728)
11	INCREASE (DECREASE) INCOME		(1,973,934)
12			
13	INCREASE (DECREASE) FIT @	35%	(690,877)
14	INCREASE (DECREASE) NOI		$ (1,283,057)

PUGET SOUND ENERGY-ELECTRIC
STORM DAMAGE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	AMOUNT		
1	NORMAL STORMS	Transmission	Distribution	Total
2	ACTUAL O&M:			
3	TWELVE MONTHS ENDED 9/30/98	13,945	255,255	269,200
4	TWELVE MONTHS ENDED 9/30/99	319,211	8,481,806	8,801,017
5	TWELVE MONTHS ENDED 9/30/00	166,215	2,374,579	2,540,794
6	TWELVE MONTHS ENDED 9/30/01	310,116	3,785,706	4,095,822
7	TWELVE MONTHS ENDED 9/30/02	(4,894)	6,583,315	6,578,420
8	TWELVE MONTHS ENDED 9/30/03	6,615	5,325,797	5,332,412
9	TOTAL NORMAL STORMS	811,206	26,806,458	27,617,664
10				
11	SIX-YEAR AVERAGE STORM EXPENSE	135,201	4,467,743	4,602,944
12				
13	CATASTROPHIC STORMS			
14	ACTUAL DEFERRED BALANCES:			
15	12/26/96 SNOW/ICE STORM			1,369,229
16	11/23/98 STORM			4,776,553
17	1/16/00 WINDSTORM			2,705,896
18	12/4/03 WIND STORM			9,645,626
19	TOTAL CATASTROPHIC STORMS			18,497,304
20				
21	THREE-YEAR AMORTIZATION FOR RATE YEAR			6,165,768
22				
23				
24	TOTAL EXPENSE FOR RATE YEAR (LINE 11+LINE 21)			10,768,712
25				
26	CHARGED TO EXPENSE FOR TEST YEAR ENDED 9/30/03:			
27	STORM DAMAGE EXPENSE (LINE 8)	6,615	5,325,797	5,332,412
28	CATASTROPHIC STORM AMORT (PER UE-011570)			6,000,000
29	TOTAL EXPENSE FOR TEST YEAR			11,332,412
30				
31	INCREASE (DECREASE) OPERATING EXPENSE (LINE 24-LINE 29)			(563,700)
32	TRANSMISSION PORTION			128,586
33	DISTRIBUTION PORTION			(858,054)
34	AMORTIZATION			165,768
35	INCREASE (DECREASE) FIT @ 35%			197,295
36				
37	INCREASE (DECREASE) NOI			366,405

PUGET SOUND ENERGY-ELECTRIC
FREDRICKSON PLANT
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	TEST YEAR	PROFORMA RYE FEB '06	ADJUSTMENT
1	FREDRICKSON PLANT RATE BASE			
2	PLANT BALANCE			
3	ACCUMULATED DEPRECIATION			
4	DEFERRED FIT			
5	FREDRICKSON PLANT RATE BASE			
6				
7	FREDRICKSON OPERATING EXPENSES:			
8				
9	DEPRECIATION EXPENSE		REDACTED	
10	PROPERTY INSURANCE			
11	PLANT PROPERTY TAXES			
12	TOTAL O&M EXPENSE			
13				
14	INCREASE (DECREASE) EXPENSE			
15				
16	INCREASE (DECREASE) FIT @			
17	INCREASE (DECREASE) NOI			

Confidential Per Protective Order in WUTC Docket Nos. UG-040640 et al.

PUGET SOUND ENERGY-ELECTRIC
LOW INCOME AMORTIZATION
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT
1	AMORTIZATION FOR TEST YEAR		$ 5,849,005
2			
3			
4	INCREASE (DECREASE) NOI		5,849,005
5			
6	INCREASE(DECREASE) FIT @	35%	2,047,152
7			
8	INCREASE(DECREASE) NOI		$ 3,801,853

PUGET SOUND ENERGY-ELECTRIC
REGULATORY ASSETS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	TEST YEAR	PROFORMA	ADJUSTMENT
1	ADJUSTMENT TO RATE BASE:			
2	REG ASSET NET OF ACCUM AMORT AND DFIT:			
3	CABOT	$ 8,512,095	$ 5,972,250	$ (2,539,845)
4	TENASKA	214,321,604	179,146,208	(35,175,396)
5	BEP	50,254,243	41,731,621	(8,522,622)
6				
7	ADJUSTMENT TO RATE BASE - NET ASSET VALUE			$ (46,237,863)

Revised 12/8/2004

Docket Numbers UG-040640 et. al
Exhibit No. ______ (JHS-E8)
PAGE 2.30

PUGET SOUND ENERGY-ELECTRIC
PRODUCTION ADJUSTMENT
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	PROFORMA AND RESTATED	PRODUCTION 1.281%	FIT 35%
1	PRODUCTION WAGE INCREASE:			
2	PURCHASED POWER	$ -	$ -	$ -
3	OTHER POWER SUPPLY	536,545	(6,873)	2,406
4	TOTAL PRODUCTION WAGE INCREASE	536,545	(6,873)	2,406
5	PAYROLL OVERHEADS	1,721,437	(22,052)	7,718
6	PROPERTY INSURANCE	2,245,253	(28,762)	10,067
7	TOTAL A&G	3,966,690	(50,813)	17,785
8				
9	DEPRECIATION / AMORTIZATION:			
10	DEPRECIATION	37,820,331	(484,478)	130,038
11	AMORTIZATION	3,280,326	(42,021)	445
12	TOTAL DEPRECIATION AND AMORTIZATION (FERC 403)	41,100,657	(526,499)	130,483
13	AMORTIZATION (FERC 407)	1,494,702	(19,147)	6,701
14	TAXES OTHER-PRODUCTION PROPERTY:			
15	PROPERTY TAXES - WASHINGTON	4,236,207	(54,266)	18,993
16	PROPERTY TAXES - MONTANA	5,321,477	(68,168)	23,859
17	ELECTRIC ENERGY TAX	1,741,844	(22,313)	7,810
18	PAYROLL TAXES	750,096	(9,609)	3,363
19	TOTAL TAXES OTHER	12,049,624	(154,356)	54,025
20	INCREASE(DECREASE) INCOME		757,689	
21	INCREASE(DECREASE) FIT			211,400
22	INCREASE(DECREASE) NOI			$ 546,289
23				
24	PRODUCTION RATE BASE:			
25	DEPRECIABLE PRODUCTION PROPERTY	$ 1,123,818,126	$ (14,396,110)	
26	LESS PRODUCTION PROPERTY ACCUM DEPR.	(580,591,154)	7,437,373	
27	NON-DEPRECIABLE PRODUCTION PROPERTY	13,260,193	(169,863)	
28	LESS PRODUCTION PROPERTY ACCUM AMORT.	(1,861,180)	23,842	
29	COLSTRIP COMMON FERC ADJUSTMENT	7,518,976	(96,318)	
30	COLSTRIP DEFERRED DEPRECIATION FERC ADJ.	2,214,968	(28,374)	
31	ENCOGEN ACQUISITION ADJUSTMENT	51,952,633	(665,513)	
32	NET PRODUCTION PROPERTY	616,312,563	(7,894,963)	
33	DEDUCT:			
34	LIBR. DEPREC. PRE 1981 (EOP)	(647,743)	8,298	
35	LIBR. DEPREC. POST 1980 (EOP)	(119,403,787)	1,529,563	
36	OTHER DEF. TAXES (EOP)	(21,361,000)	273,634	
37	SUBTOTAL	(141,412,530)	1,811,495	
38		-	-	
39	ADJUSTMENT TO PRODUCTION RATE BASE	474,900,033	(6,083,468)	
40				
41	REGULATORY ASSETS RATE BASE:			
42	BPA POWER EXCHANGE INVESTMENT	41,731,621	(534,582)	
43	TENASKA REGULATORY ASSET	179,146,208	(2,294,863)	
44	CABOT OIL REGULATORY ASSET	5,972,250	(76,505)	
45	WHITE RIVER RELICENSING COSTS	17,900,360	(229,304)	
46	WHITE RIVER PLANT COSTS	41,343,483	(529,610)	
47	ADJUSTMENT TO REGULATORY ASSETS RATE BASE	286,093,922	(3,664,864)	
48				
49	TOTAL ADJUSTMENT TO RATE BASE	$ 760,993,956	$ (9,748,332)	

Docket Number UE-04_____
Exhibit No. _____ (JHS-E9)
PAGE 1.01

PUGET SOUND ENERGY-ELECTRIC
GENERAL RATE INCREASE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		
1	RATE BASE	$	2,546,059,451
2	RATE OF RETURN		9.12%
3			
4	OPERATING INCOME REQUIREMENT		232,200,622
5			
6	PRO FORMA OPERATING INCOME		170,149,659
7	OPERATING INCOME DEFICIENCY		62,050,963
8			
9	CONVERSION FACTOR		0.6207738
10	REVENUE REQUIREMENT DEFICIENCY		99,957,446
11	ASSIGNMENT TO LARGE FIRM WHOLESALE		93,378
12	ASSIGNMENT TO SMALL FIRM WHOLESALE		31,885
13		$	99,832,183

Docket Number UE-04______
Exhibit No. ______ (JHS-E9)
PAGE 1.02

PUGET SOUND ENERGY-ELECTRIC
PRO FORMA COST OF CAPITAL
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	PRO FORMA CAPITAL %	COST %	COST OF CAPITAL
1	DEBT	54.96%	6.96%	3.83%
2	PREFERRED	0.04%	8.51%	0.00%
3	EQUITY	45.00%	11.75%	5.29%
4	TOTAL	100.00%		9.12%
5				
6	AFTER TAX DEBT (LINE 1 * 65%)	54.96%	4.52%	2.49%
7	PREFERRED	0.04%	8.51%	0.00%
8	EQUITY	45.00%	11.75%	5.29%
9	TOTAL AFTER TAX COST OF CAPITAL	100.00%		7.78%

PUGET SOUND ENERGY-ELECTRIC
CONVERSION FACTOR
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		RATE
1	BAD DEBTS		0.0045080
2	ANNUAL FILING FEE		0.0019000
3	STATE UTILITY TAX ((1 - LINE 1) * 3.873%)	3.873%	0.0385554
4			
5	SUM OF TAXES OTHER		0.0449634
6			
7	FEDERAL INCOME TAX ((1 - LINE 5) * 35%)	35%	0.3342628
8	CONVERSION FACTOR (1 - (LINE 5 + LINE 7))		0.6207738

Exhibit No. (JHS-E9)
PAGE 1.04

Puget Sound Energy
Electric Rate Base
As of September 30, 2003

Electric 68.24%

Gas 31.76%

1	Account	Description	AMA 12 Months Ended Sep-03	Current Month Period End Sep-03
2				
3		**Rate Base**		
4	10100001	Electric Plant in Service	$ 4,058,827,720	$ -
5	101/118	Common Plant-Allocation to Electric	252,614,535	
6	114	Electric Plant Aquisition Adjustment	77,871,127	
6a	18230001	Tenaska	227,519,604	
6b	18230171	Cabot	12,239,095	
7	18230041	Colstrip Common FERC Adj - Reg Asset	21,589,277	
8	18230051	Accum Amortization Colstrip-Common FERC	(9,367,928)	
9	18230061	Colstrip Def Depr FERC Adj - Reg	2,947,396	
10	18230071	BPA Power Exch Invstmt - Reg Asset	113,632,921	
11	18230081	BPA Power Exch Inv Amortization - Reg Asset	(63,378,678)	
12	18230031	Electric - Def AFUDC - Regulatory Asset	29,097,076	
13				
14	10500001	Electric - Plant Held for Future Use	6,772,284	
15	10500003	Common Plant Held for Fut Use-Alloc to Electric	-	
16	106	Electric - Const Completed Non Classified	-	
17	108XXXX1	Elec-Accum Depreciation	(1,703,089,065)	
18	108XXXX3	Common Accum Depr-Allocation to Electric	(18,270,828)	
19	111XXXX1	Elec-Accum Amortization	(13,282,154)	
20	111XXXX3	Common Accum Amort-Allocation to Electric	(57,572,037)	
21	115	Accum Amort Acq Adj - Electric	(25,422,002)	
22	18230221	Accum Unamort Consrv Costs	154,506	
23	19000041	CIAC after 10/8/76 - Accum Def Income Tax		33,918
24	19000051	CIAC - 1986 Changes - Accum Def Income Tax		91,427
25	19000061	CIAC - 7/1/87 - Accum Def Income Tax		39,518,432
26	19000093	Vacation Pay - Accum Def Inc Taxes		1,971,454
27	19000191	RB-Consv Pre91 Tax Settlmt - Accum Def Inc Tax	-	
28	235000X1	Customer Deposits - Electric	(8,752,784)	
29	25400081	Residential Exchange	-	
30	252	Cust Advances for Construction	(23,664,861)	
31	28200101	Major Projects - Property Tax Expense		(3,497,000)
32	28200111	Def Inc Tax - Pre 1981 Additions		(647,743)
33	28200121	Def Inc Tax - Post 1980 Additions		(337,279,618)
34	28200131	Colstrip 3 & 4 Deferred Inc Tax		(939,000)
35	28200141	Excess Def Taxes - Centralia Sale		(32,874)
36	28300161	Def Inc Tax - Energy Conservation	-	
37	28300261	Def FIT Bond Redemption Costs		(4,409,226)
37a	28300451	Accum Def Inc Tax - Tenaska Purchase		(13,198,000)
37b	28300461	Accum Def Inc Tax - Cabot Gas Contract		(3,727,000)
37c	Various	Working Capital Adjustments (Working Capital, Line 101)		(68,291,281)
38	124001X1	Conservation Rate Base		-
39		1995 Conservation Trust Rate Base	11,569,864	
40		1997 Conservation Trust Rate Base	-	
41		Working Capital- Rate Base	15,068,558	
42		Rate Base	$ 2,907,103,625	$ (390,406,512)
43				
44				$ 2,516,697,113
45				
46		Utility Plant in Service	Lines 4-6 & 14-21	$ 2,578,449,579
47		Deferred Debits	Lines 6a-12 & 22	334,433,269
48		Deferred Taxes	Lines 23-27 & 31-37	(390,406,512)
49		Conservation Trust	Lines 39-40	11,569,864
50		Allowance for Working Capital	Line 41	15,068,558
51		Other	Lines 28-30	(32,417,645)
52		Total Rate Base		$ 2,516,697,113

Exhibit No. (JHS-E9)
PAGE 1.05

Puget Sound Energy
Electric Working Capital
As of September 30, 2003

	Allocator	Tax Factor
Electric	68.24%	85.61%
Gas	31.76%	[illegible]

Line No.	Description	Company Supplemental 12 Months Ended 9/30/2003-AMA	Staff Adjustments	Staff Working 12 Months Ended 9/30/2003-AMA	Company Adjustments	Company Rebuttal 12 Months Ended 9/30/2003-AMA
1	Average Invested Capital					
2	Common Stock	859,037,900		859,037,900		859,037,900
3	Preferred Stock	381,901,588		381,901,588		381,901,588
4	Additional Paid in Capital	484,624,357		484,624,357		484,624,357
5	Unamortized Debt Expense	(23,839,290)		(23,839,290)		(23,839,290)
6	Unappropriated Retained Earnings	75,953,779		75,953,779		75,953,779
7	Notes Payable - Misc	-		-		-
8	Long Term Debt	2,088,790,800		2,088,790,800		2,088,790,800
9	Short Term Debt	50,427,833		50,427,833		50,427,833
10	Accumulated Deferred ITC	3,865,613		3,865,613		3,865,613
11	Deferred Debits-Other	(909,148)		(909,148)		(909,148)
12	Unamortized Gain/Loss on Debt	(8,683,895)		(8,683,895)		(8,683,895)
13	1995 Conservation Trust Bonds Payable	15,096,321		15,096,321		15,096,321
14	Total Average Invested Capital	3,926,265,858		3,926,265,858		3,926,265,858
15						
16	Average Electric Operating Investments					
17						
18	Electric Plant in Service (includes acquisition adj)	4,136,698,847		4,136,698,847		4,136,698,847
19	Electric Future Use Property	6,772,284		6,772,284		6,772,284
20	Customer Advances for Construction	(23,664,861)		(23,664,861)		(23,664,861)
21	Customer Deposits	(8,752,784)		(8,752,784)		(8,752,784)
22	Deferred Taxes	(316,659,395)	(49,027,867)	(365,687,262)	(64,731,602)	(381,390,997)
23	Deferred Debits - Other	335,236,065	-	335,236,065		335,236,065
24	Less: Accumulated Depreciation	(1,741,793,221)		(1,741,793,221)		(1,741,793,221)
25	Completed Const. Not Classified	-		-		-
26	Conservation Investment	154,506		154,506		154,506
26a	1995 Conservation Trust Asset	11,569,864		11,569,864		11,569,864
27	Average Electric Operating Investment-Direct	2,399,561,305		2,350,533,438		2,334,829,703
28	Common Plant-Allocation to Electric	252,614,535		252,614,535		252,614,535
29	Common Plant Held for Fut Use-Allocation to Electric	-		-		-
30	Common Accum Depr-Allocation to Electric	(75,842,866)		(75,842,866)		(75,842,866)
31	Common Deferred Taxes-Allocation to Electric	1,681,746		1,681,746		1,681,746
32	Common Deferred Debits-Allocation to Electric	-		-		-
33	Common Conservation Investment-Allocation to Electric	-		-		-
33a	Investment in Associated Companies-Rainier Receivables	8,955,324		8,955,324		8,955,324
34	Average Common Operating Invest-Allocation to Electric	187,408,739		187,408,739		187,408,739
35	Total Average Electric Operating Investment	2,586,970,044		2,537,942,177		2,522,238,442
36						
37						
38	Nonoperating, Gas Plant & Electric Plant Not In Service					
39	Nonutility Property at Cost	1,789,905		1,789,905		1,789,905
40	Investment in Associated Companies	124,657,347		124,657,347		124,657,347
41	Other Investments & FAS 133	39,007,587		39,007,587		39,007,587
42	Interest Bearing Regulatory Assets	-		-		-
43	Electric CWIP	87,672,093		87,672,093		87,672,093
44	Common CWIP-Allocation to Electric	8,485,355		8,485,355		8,485,355
45	Other Electric Work in Progress	21,767		21,767		21,767
46	Other Common Work in Progress	1,391,143		1,391,143		1,391,143
47	Deferred Items - Other Electric	152,222,970	2,085,212	154,308,182		152,222,970
48	Less: Related Deferred FIT	(153,815,441)		(153,815,441)		(153,815,441)
49	Common Deferred Items	(42,749,955)	48,148,496	5,398,541	48,148,496	5,398,541
50	Less: Common Related Deferred FIT-Allocation to Electric	9,369,425		9,369,425		9,369,425
51	Temporary Cash Investments	50,966,149		50,966,149		50,966,149
52	Electric Preliminary Surveys	78,965		78,965		78,965
53	Gas Plant in Service	1,634,697,162		1,634,697,162		1,634,697,162
54	Common Plant in Service-Allocation to Gas	117,570,891		117,570,891		117,570,891
55	Gas Completed Construction Not Classified	-		-		-
56	Gas Future Use	-		-		-
57	Common Plant Held for Fut Use-Allocation to Gas	-		-		-
58	Gas Construction Work in Progress	28,009,840		28,009,840		28,009,840
59	Common CWIP-Allocation to Gas	3,949,221		3,949,221		3,949,221

Exhibit No. (JHS-E9)
PAGE 1.05

Puget Sound Energy
Electric Working Capital
As of September 30, 2003

	Allocator	Tax Factor
Electric	68.24%	85.51%
Gas	31.76%	[redacted]

Line No.	Description	Company Supplemental 12 Months Ended 9/30/2003-AMA	Staff Adjustments	Staff Working 12 Months Ended 9/30/2003-AMA	Company Adjustments	Company Rebuttal 12 Months Ended 9/30/2003-AMA
60	Gas Stored Underground	3,246,534		3,246,534		3,246,534
61	Less: Gas Accumulated Depreciation	(505,508,739)		(505,508,739)		(505,508,739)
62	Common Plant Accum Depr-Allocation to Gas	(35,298,497)		(35,298,497)		(35,298,497)
63	Gas Customer Contribution/Advances	(17,174,520)		(17,174,520)		(17,174,520)
64	Deferred Taxes - Other Gas	(187,428,993)		(187,428,993)		(187,428,993)
65	Gas Nonoperating Items	(28,044,350)		(28,044,350)		(28,044,350)
65a	Common Current Accts-Gas Share	(3,198,054)		(3,198,054)		(3,198,054)
65b	Gas Current Accts	48,962,510	-	48,962,510		48,962,510
66	Common Non-Operating Items	(90,154,255)	49,219,975	(40,934,280)	64,731,602	(25,422,653)
67	Common Other Operating Items-Allocation to Gas	4,360,682	15,323,190	19,683,872	15,323,190	19,683,872
68				-		-
69	Total Nonoperating & Gas Investments	1,253,086,742		1,367,863,615		1,381,290,029
				-		-
70	Total Average Investments	3,840,056,786		3,905,805,792		3,903,528,472
71	Total Investor Supplied Working Capital	$ 86,209,072		$ 20,460,066		$ 22,737,386
72						
73	Total Average Investments	3,840,056,786		3,905,805,792		3,903,528,472
74	Less: Electric CWIP	(96,157,448)		(96,157,448)		(96,157,448)
	Interest Bearing Regulatory Assets	-		-		-
75	Other Work in Progress	(1,412,910)		(1,412,910)		(1,412,910)
76	Preliminary Surveys	(78,965)		(78,965)		(78,965)
77	Total	3,742,407,463		3,808,156,469		3,805,879,149
78						
79	Working Capital %	2.30%		0.54%		0.60%
80						
81	Non Electric Working Capital	26,616,340		6,824,475		7,668,828
82						
83	Operating Working Capital	$ 59,592,733		$ 13,635,591		$ 15,068,558
84						
84						
85						
86						
87						
88						

Line No.	Account	Description	Alloc	Working Capital Amt	Rate Base Amt
89					
90					
91					
92	Non Operating to Working Capital				
93	14209993	Cust A/R Clmg CLX	68.24%	15,323,190	
94	Non Operating to Operating				
95	19000121	Cabot Gas DT	100.00%	2,151,750	2,718,000
96	28300023	Def Tax CLX Amort	68.24%	(181,803)	(543,190)
97	28300193	Def Inc Tax-SAP	68.24%	(4,106,285)	(4,813,650)
98	28300501	IRS Carryover Adj-CLX	68.24%	(19,779,876)	(22,732,109)
99				(21,916,214)	(25,370,949)
100	28300513	Indirect Cost Adjustment	59.15%	(42,815,388)	(42,920,332)
101				(64,731,602)	(68,291,281)

Puget Sound Energy
Allocation Methods
For Twelve Months Ended September 30, 2003

Method	Description		Electric	Gas	Total
	* 12 Month Average Number of Customers	9/30/2003	963,664	628,082	1,591,746
1	Percent		60.54%	39.46%	100.00%
	* Joint Meter Reading Customers	9/30/2003	619,724	332,671	952,395
2	Percent		65.07%	34.93%	100.00%
	* Non-Production Plant				
	Distribution	9/30/2003	$ 2,504,397,382	$ 1,475,499,325	$ 3,979,896,708
	Transmission	9/30/2003	274,609,259	98,770,380	373,379,640
	Direct General Plant	9/30/2003	136,210,907	50,818,388	187,029,295
	Total		$ 2,915,217,549	$ 1,625,088,093	$ 4,540,305,642
3	Percent		64.21%	35.79%	100.00%
	* 4-Factor Allocator				
	Number of Customers	9/30/2003	963,664	628,082	1,591,746
	Percent		60.54%	39.46%	100.00%
	Labor - Direct Charge to O&M	9/30/2003	$ 28,154,990	$ 14,311,924	$ 42,466,914
	Percent		66.30%	33.70%	100.00%
	T&D O&M Expense (Less Labor)	9/30/2003	$ 41,897,721	$ 11,543,859	$ 53,441,580
	Percent		78.40%	21.60%	100.00%
	Net Classified Plant (Excluding General Plant)	9/30/2003	$ 2,321,603,082	$ 1,105,973,344	$ 3,427,576,426
	Percent		67.73%	32.27%	100.00%
	Total Percentages		272.97%	127.03%	400.00%
4	Percent		68.24%	31.76%	100.00%
	* Labor				
	Benefit Assessment Distribution	9/30/2003	$ 5,944,648	$ 3,322,937	$ 9,267,585
	Total		$ 5,944,648	$ 3,322,937	$ 9,267,585
5	Percent		64.14%	35.86%	100.00%
	* Current & Deferred FIT	9/30/2003	$ 52,079,273	$ 8,822,100	$ 60,901,373
6	Percent		85.51%	14.49%	100.00%

Appendix B – Gas

PUGET SOUND ENERGY-GAS
RESULTS OF OPERATIONS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.		ACTUAL RESULTS OF OPERATIONS	TOTAL ADJUSTMENTS	ADJUSTED RESULTS OF OPERATIONS	REVENUE REQUIREMENT DEFICIENCY	AFTER RATE INCREASE
1	OPERATING REVENUES:					
2	SALES TO CUSTOMERS	$ 522,553,139	$ 169,574,795	$ 692,127,934	$ 42,437,416	$ 734,565,350
3	MUNICIPAL ADDITIONS	21,624,997	4,802,002	26,426,999	1,670,637	28,097,636
4	OTHER OPERATING REVENUES	11,020,477	991,673	12,012,150	2,076,235	14,088,385
5	TOTAL OPERATING REVENUES	$ 555,198,613	$ 175,368,470	$ 730,567,083	$ 46,184,288	$ 776,751,371
6						
7						
8	OPERATING REVENUE DEDUCTIONS:					
9						
10	GAS COSTS:					
11						
12	PURCHASED GAS	$ 260,366,708	$ 162,756,809	$ 423,123,517	$ -	$ 423,123,517
13						
14	TOTAL PRODUCTION EXPENSES	$ 260,366,708	$ 162,756,809	$ 423,123,517	$ -	$ 423,123,517
15						
16	OTHER POWER SUPPLY EXPENSES	$ 1,134,458	$ 28,986	$ 1,163,444	$ -	$ 1,163,444
17	TRANSMISSION EXPENSE	360,965	14,581	375,547		375,547
18	DISTRIBUTION EXPENSE	25,045,610	879,943	25,925,553		25,925,553
19	CUSTOMER ACCOUNT EXPENSES	20,751,969	134,501	20,886,470		20,886,470
20	CUSTOMER SERVICE EXPENSES	4,862,124	(2,690,087)	2,172,037		2,172,037
21	CONSERVATION AMORTIZATION	2,008,929	(1,160,780)	848,149		848,149
22	ADMIN & GENERAL EXPENSE	26,373,760	6,473,520	32,847,280	258,094	33,105,375
23	DEPRECIATION	57,635,006	241,312	57,876,318		57,876,318
24	AMORTIZATION	9,600,784	0	9,600,784		9,600,784
25	AMORTIZATION OF PROPERTY LOSS	36,543	0	36,543		36,543
26	OTHER OPERATING EXPENSES	600,936	0	600,936		600,936
27	TAXES OTHER THAN F.I.T.	56,143,334	15,354,986	71,498,320	3,564,093	75,062,413
28	FEDERAL INCOME TAXES	(11,871,394)	3,977,546	(7,893,848)	14,826,735	6,932,887
29	DEFERRED INCOME TAXES	20,693,494	918,606	21,612,100		21,612,100
30	TOTAL OPERATING REV. DEDUCT.	$ 213,376,518	$ 24,173,115	$ 237,549,633	$ 18,648,923	$ 256,198,556
31						
32	NET OPERATING INCOME	$ 81,455,387	$ (11,561,454)	$ 69,893,933	$ 27,535,365	$ 97,429,298
33						
34	RATE BASE	$ 1,065,156,799	$3,146,890	$ 1,068,303,689	$ -	$ 1,068,303,689
35						
36	RATE OF RETURN	7.65%		6.54%		9.12%
37						
38	RATE BASE:					
39	UTILITY PLANT IN SERVICE AND OTHER ASSETS	$ 1,755,514,587	$ 3,146,890	$ 1,758,661,477		160,389,927
40	ACCUMULATED DEPRECIATION	(540,807,236)	-	(540,807,236)		(49,321,620)
41	ACCUMULATED DEFERRED FIT - LIBERALIZED	(134,342,956)	-	(134,342,956)		(12,252,078)
42	DEPRECIATION AND OTHER LIABILITIES	(17,174,520)	-	(17,174,520)		(1,566,316)
43	TOTAL NET INVESTMENT	$ 1,063,189,875	$ 3,146,890	$ 1,066,336,765		97,249,913
44	ALLOWANCE FOR WORKING CAPITAL	1,966,924	-	1,966,924		179,383
45	TOTAL RATE BASE	$ 1,065,156,799	$ 3,146,890	$ 1,068,303,689		97,429,296

PUGET SOUND ENERGY-GAS
STATEMENT OF OPERATING INCOME AND ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
RESTATING AND PRO FORMA ADJUSTMENTS

LINE NO.		ACTUAL RESULTS OF OPERATIONS 12ME Sept. 30, 2003	REVENUE & PURCHASED GAS 2.01	FEDERAL INCOME TAX 2.02	TAX BENEFIT OF PRO FORMA INTEREST 2.03	DEPRECIATION/ AMORTIZATION 2.04	CONSERVATION 2.05	BAD DEBTS 2.06
1	OPERATING REVENUES							
2	SALES TO CUSTOMERS	$ 522,553,139	$ 169,574,795	$ -	$ -	$ -	$ -	$ -
3	MUNICIPAL ADDITIONS	21,624,997	4,802,002					
4	OTHER OPERATING REVENUES	11,020,477	991,673					
5	TOTAL OPERATING REVENUES	$ 555,198,613	$ 175,368,470	$ -	$ -	$ -	$ -	$ -
6								
7								
8	OPERATING REVENUE DEDUCTIONS:							
9								
10	GAS COSTS:							
11								
12	PURCHASED GAS	$ 260,366,708	$ 162,756,809	$ -	$ -	$ -	$ -	$ -
13								
14	TOTAL PRODUCTION EXPENSES	$ 260,366,708	$ 162,756,809	$ -	$ -	$ -	$ -	$ -
15								
16	OTHER ENERGY SUPPLY EXPENSES	$ 1,134,458	$ -	$ -	$ -	$ -	$ -	$ -
17	TRANSMISSION EXPENSE	360,965						
18	DISTRIBUTION EXPENSE	25,045,610						
19	CUSTOMER ACCTS EXPENSES	20,751,969	646,822					(867,438)
20	CUSTOMER SERVICE EXPENSES	4,862,124						
21	CONSERVATION AMORTIZATION	2,008,929					(1,160,780)	
22	ADMIN & GENERAL EXPENSE	26,373,760	-					-
23	DEPRECIATION	57,635,006				241,312		
24	AMORTIZATION	9,600,784						
25	AMORTIZATION OF PROPERTY LOSS	36,543						
26	OTHER OPERATING EXPENSES	600,936						
27	TAXES OTHER THAN F.I.T.	56,143,334	13,866,582					
28	FEDERAL INCOME TAXES	(11,871,394)	(665,610)	302,494	6,007,908	(84,459)	406,273	303,603
29	DEFERRED INCOME TAXES	20,693,494		918,606				
30	TOTAL OPERATING REV. DEDUCT.	$ 213,376,518	$ 13,847,794	$ 1,221,100	$ 6,007,908	$ 156,853	$ (754,507)	$ (563,835)
31								
32	NET OPERATING INCOME	$ 81,455,387	$ (1,236,133)	$ (1,221,100)	$ (6,007,908)	$ (156,853)	$ 754,507	$ 563,835
33								
34	RATE BASE	$ 1,065,156,799				$ (120,656)		
35								
36	RATE OF RETURN	7.65%						
37								
38	RATE BASE:							
39	UTILITY PLANT IN SERVICE AND OTHER ASSETS	$ 1,755,514,587	$ -	$ -	$ -	$ (120,656)	$ -	$ -
40	ACCUMULATED DEPRECIATION	(540,807,236)						
41	ACCUMULATED DEFERRED FIT - LIBERALIZED	(134,342,956)						
42	DEPRECIATION AND OTHER LIABILITIES	(17,174,520)						
43	TOTAL NET INVESTMENT	$ 1,063,189,875	$ -	$ -	$ -	$ (120,656)	$ -	$ -
44	ALLOWANCE FOR WORKING CAPITAL	1,966,924						
45	TOTAL RATE BASE	$ 1,065,156,799	$ -	$ -	$ -	$ (120,656)	$ -	$ -

PUGET SOUND ENERGY-GAS
STATEMENT OF OPERATING INCOME AND ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
RESTATING AND PRO FORMA ADJUSTMENTS

LINE NO.		MISCELLANEOUS OPERATING EXPENSE 2.07	PROPERTY TAXES 2.08	EXCISE TAX & FILING FEE 2.09	RATE CASE EXPENSES 2.10	PROPERTY& LIABILITY INS 2.11	PENSION PLAN 2.12
1	OPERATING REVENUES						
2	SALES TO CUSTOMERS	$ -	$ -	$ -	$ -	$ -	$ -
3	MUNICIPAL ADDITIONS						
4	OTHER OPERATING REVENUES						
5	TOTAL OPERATING REVENUES	$ -	$ -	$ -	$ -	$ -	$ -
6							
7							
8	OPERATING REVENUE DEDUCTIONS:						
9							
10	GAS COSTS:						
11							
12	PURCHASED GAS	$ -	$ -	$ -	$ -	$ -	$ -
13							
14	TOTAL PRODUCTION EXPENSES	$ -	$ -	$ -	$ -	$ -	$ -
15							
16	OTHER ENERGY SUPPLY EXPENSES	$ -	$ -	$ -	$ -	$ -	$ -
17	TRANSMISSION EXPENSE						
18	DISTRIBUTION EXPENSE						
19	CUSTOMER ACCTS EXPENSES						
20	CUSTOMER SERVICE EXPENSES						
21	CONSERVATION AMORTIZATION						
22	ADMIN & GENERAL EXPENSE	(152,837)		106,472	$253,257	188,407	4,786,934
23	DEPRECIATION						
24	AMORTIZATION						
25	AMORTIZATION OF PROPERTY LOSS						
26	OTHER OPERATING EXPENSES						
27	TAXES OTHER THAN F.I.T.	(10,699)	1,260,798	72,367			
28	FEDERAL INCOME TAXES	57,238	(441,279)	(62,594) $	(88,640)	(65,942)	(1,675,427)
29	DEFERRED INCOME TAXES						
30	TOTAL OPERATING REV. DEDUCT.	$ (106,298)	$ 819,519	$ 116,245	$ 164,617	$ 122,465	$ 3,111,507
31							
32	NET OPERATING INCOME	$ 106,298	$ (819,519)	$ (116,245)	$ (164,617)	$ (122,465)	$ (3,111,507)
33							
34	RATE BASE	$ 3,267,546					
35							
36	RATE OF RETURN						
37							
38	RATE BASE:						
39	UTILITY PLANT IN SERVICE AND OTHER ASSETS	$ 3,267,546	$ -	$ -	$ -	$ -	$ -
40	ACCUMULATED DEPRECIATION						
41	ACCUMULATED DEFERRED FIT - LIBERALIZED						
42	DEPRECIATION AND OTHER LIABILITIES						
43	TOTAL NET INVESTMENT	$ 3,267,546	$ -	$ -	$ -	$ -	$ -
44	ALLOWANCE FOR WORKING CAPITAL						
45	TOTAL RATE BASE	$ 3,267,546	$ -	$ -	$ -	$ -	$ -

PUGET SOUND ENERGY-GAS
STATEMENT OF OPERATING INCOME AND ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
RESTATING AND PRO FORMA ADJUSTMENTS

LINE NO.		WAGE INCREASE 2.13	INVESTMENT PLAN 2.14	EMPLOYEE INSURANCE 2.15	LOW INCOME AMORTIZATION 2.16	GAS WATER HEATER PROGRAM 2.17	TOTAL ADJUSTMENTS	ADJUSTED RESULTS OF OPERATIONS
1	OPERATING REVENUES							
2	SALES TO CUSTOMERS	$ -	$ -	$ -	$ -	$ -	$ 169,574,795	$ 692,127,934
3	MUNICIPAL ADDITIONS						4,802,002	26,426,999
4	OTHER OPERATING REVENUES						991,673	12,012,150
5	TOTAL OPERATING REVENUES	$ -	$ -	$ -	$ -	$ -	$ 175,368,470	$ 730,567,083
6								
7								
8	OPERATING REVENUE DEDUCTIONS:							
9								
10	GAS COSTS:							
11								
12	PURCHASED GAS	$ -	$ -	$ -	$ -	$ -	$ 162,756,809	$ 423,123,517
13								
14	TOTAL PRODUCTION EXPENSES	$ -	$ -	$ -	$ -		$ 162,756,809	$ 423,123,517
15								
16	OTHER ENERGY SUPPLY EXPENSES	$ 28,986	$ -	$ -	$ -		$ 28,986	$ 1,163,444
17	TRANSMISSION EXPENSE	14,581					14,581	375,547
18	DISTRIBUTION EXPENSE	879,943					879,943	25,925,553
19	CUSTOMER ACCTS EXPENSES	355,118					134,501	20,886,470
20	CUSTOMER SERVICE EXPENSES	67,148			(2,757,235)	-	(2,690,087)	2,172,037
21	CONSERVATION AMORTIZATION						(1,160,780)	848,149
22	ADMIN & GENERAL EXPENSE	491,762	89,631	709,894		-	6,473,520	32,847,280
23	DEPRECIATION					-	241,312	57,876,318
24	AMORTIZATION						-	9,600,784
25	AMORTIZATION OF PROPERTY LOSS						-	36,543
26	OTHER OPERATING EXPENSES						-	600,936
27	TAXES OTHER THAN F.I.T.	165,938					15,354,986	71,498,320
28	FEDERAL INCOME TAXES	(701,217)	(31,371)	(248,463)	965,032	-	3,977,546	(7,893,848)
29	DEFERRED INCOME TAXES						918,606	21,612,100
30	TOTAL OPERATING REV. DEDUCT.	$ 1,302,260	$ 58,260	$ 461,431	$ (1,792,203)	$ -	$ 24,173,115	$ 237,549,633
31								
32	NET OPERATING INCOME	$ (1,302,260)	$ (58,260)	$ (461,431)	$ 1,792,203	$ -	$ (11,561,454)	$ 69,893,933
33								
34	RATE BASE					$ -	$ 3,146,890	$ 1,068,303,689
35								
36	RATE OF RETURN							6.54%
37								
38	RATE BASE:							
39	UTILITY PLANT IN SERVICE AND OTHER ASSETS	$ -	$ -	$ -	$ -	$ -	$ 3,146,890	$ 1,758,661,477
40	ACCUMULATED DEPRECIATION					-	-	(540,807,236)
41	ACCUMULATED DEFERRED FIT - LIBERALIZED					-	-	(134,342,956)
42	DEPRECIATION AND OTHER LIABILITIES						-	(17,174,520)
43	TOTAL NET INVESTMENT	$ -	$ -	$ -	$ -	$ -	$ 3,146,890	$ 1,066,336,765
44	ALLOWANCE FOR WORKING CAPITAL						-	1,966,924
45	TOTAL RATE BASE	$ -	$ -	$ -	$ -	$ -	$ 3,146,890	$ 1,068,303,689

PUGET SOUND ENERGY-GAS
REVENUE & PURCHASED GAS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		ACTUAL	RESTATED	ADJUSTMENT
1	**OPERATING REVENUE**		$ 522,553,139	$ 593,754,354	$ 71,201,215
2					
3	PROFORMA OPERATING REVENUE			$ 692,127,934	$ 98,373,580
4					
5	INCREASE TO OPERATING REVENUE				$ 169,574,795
6					
7	MUNICIPAL ADDITIONS		$ 21,624,997	$ 26,426,999	$ 4,802,002
8					
9	OTHER OPERATING REVENUE		$ 11,020,477	$ 11,664,675	$ 644,198
10					
11	REVENUE BEFORE OTHER ADJUSTMENTS		$ 555,198,613	$ 730,219,608	$ 175,020,995
12					
13	MISC CUSTOMER CHARGE REVENUE				$ 347,475
14					
15					
16	TOTAL REVENUE ADJUSTMENTS				$ 175,368,470
17					
18	**OPERATING EXPENSE**				
19	PURCHASED GAS		$ 260,366,708	$ 423,123,517	$ **162,756,809**
20					
21	OTHER OPERATIONS EXPENSE (APUA)	0.37%			646,822
22					
23	TAXES				
24	GROSS RECEIPTS	7.91%	3.8378%	6,730,277	13,866,582
25			3.8793%	6,803,104	
26	FEDERAL INCOME TAXES		0.1900%	333,200	
27	CURRENT	35%	7.9071%	13,866,581	(665,610)
28					
29					
30					
31	TOTAL INCREASE/(DECREASE) REVENUE				$ 175,368,470
32					
33	TOTAL INCREASE/(DECREASE) OPERATING EXPENSE BEFORE FIT				$ 177,270,213
34					
35	TOTAL INCREASE/(DECREASE) FIT				$ (665,610)
36					
37	TOAL INCREASE/(DECREASE) NOI				$ (1,236,133)

PUGET SOUND ENERGY-GAS
FEDERAL INCOME TAX
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			AMOUNT
1	TAXABLE INCOME		$	(33,054,000)
2				
3	FEDERAL INCOME TAX			
4	CURRENT FIT @	35%		(11,568,900)
5	DEFERRED FIT - DEBIT			46,238,850
6	DEFERRED FIT - CREDIT			(23,990,750)
7	DEFERRED FIT - INV TAX CREDIT, NET OF AMORTIZATION			(636,000)
8	TOTAL RESTATED FIT		$	10,043,200
9				
10	FIT PER BOOKS:			
11	CURRENT FIT		$	(11,871,394)
12	DEFERRED FIT - DEBIT			44,894,221
13	DEFERRED FIT - CREDIT			(23,568,000)
14	DEFERRED FIT - INV TAX CREDIT, NET OF AMORTIZATION			(632,727)
15	TOTAL CHARGED TO EXPENSE		$	8,822,100
16				
17	INCREASE(DECREASE) FIT		$	302,494
18	INCREASE(DECREASE) DEFERRED FIT			921,879
19	INCREASE(DECREASE) ITC			(3,273)
20	INCREASE(DECREASE) NOI		$	(1,221,100)

PUGET SOUND ENERGY-GAS
TAX BENEFIT OF PRO FORMA INTEREST
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			AMOUNT
1	RATE BASE	$ 1,068,303,689		
2	DEDUCTIBLE CWIP	14,897,280		
3		$ 1,083,200,969		
4				
5	WEIGHTED COST OF DEBT	3.83%		
6	RESTATED INTEREST		$	41,486,597
7				
8	<u>INTEREST EXPENSE ITEMS PER BOOKS:</u>			
9	INTEREST ON LONG TERM DEBT	$ 53,270,991		
10	AMORTIZATION OF DEBT DISCOUNT			
11	AND EXPENSE, NET OF PREMIUMS	1,223,952		
12	OTHER INTEREST EXPENSE	4,157,105		
13	CHARGED TO EXPENSE IN TEST YEAR			58,652,048
14	INCREASE (DECREASE) INTEREST EXPENSE		$	(17,165,451)
15				
16	INCREASE (DECREASE) FIT @	35%		6,007,908
17	INCREASE (DECREASE) NOI		$	(6,007,908)

PUGET SOUND ENERGY-GAS
DEPRECIATION/AMORTIZATION
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			ADJUSTMENT
1	RESTATED			
2	ACTUAL ACCT 403-DEPRECIATION EXPENSE		$	57,593,286
3	RESTATED ACCT 403-DEPRECIATION EXPENSE			57,834,598
4	INCREASE (DECREASE) DEPRECIATION EXPENSE			(241,312)
5				
6	INCREASE (DECREASE) FIT	35%		(84,459)
7	INCREASE (DECREASE) NOI			(156,853)
8				
9	ADJUST RATE BASE FOR LINE 4 @	50%		(120,656)
10				
	ADJUSTMENT TO RATE BASE		$	(120,656)

PUGET SOUND ENERGY-GAS
CONSERVATION
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			ADJUSTMENT
1	RESTATING			
2	ACTUAL CONSERVATION TRACKER AMORTIZATION		$ 1,366,028	
3	RESTATED CONSERVATION TRACKER AMORTIZATION		-	
4	INCREASE (DECREASE) EXPENSE		(1,366,028)	
5	INCREASE (DECREASE) OPERATING INCOME			$ 1,366,028
6				
7	ACTUAL LOST MARGIN ON GAS WATER HEATER		(88,357)	
8	RESTATED LOST MARGIN ON GAS WATER HEATER		-	
9	INCREASE (DECREASE) EXPENSE		88,357	
10	INCREASE (DECREASE) OPERATING INCOME			(88,357)
11				
12	PROFORMA - (RYE 02/28/2006)			
13	CONSERVATION REGULATORY ASSET-ACCT #18230422 WATER HEATER PRGM		350,674	
14	CONSERVATION AMORTIZATION FOR RATE YEAR (BASE ON 3 YEAR AVERAGE)		116,891	
15	INCREASE (DECREASE) OPERATING INCOME			(116,891)
16				
17				
18	INCREASE (DECREASE) INCOME			$ 1,160,780
19	INCREASE (DECREASE) FIT	35%		406,273
20				
21	INCREASE (DECREASE) NOI			$ 754,507

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PUGET SOUND ENERGY-GAS
BAD DEBTS
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION								AMOUNT
1	12 MOS ENDED 09/30/1999	$	1,649,551	$	464,743,911	$	464,743,911		0.3549375%
2	12 MOS ENDED 09/30/2000	$	1,466,047	$	539,050,873	$	539,050,873		0.2719682%
3	12 MOS ENDED 09/30/2002	$	3,466,159	$	780,673,537	$	780,673,537		0.4439959%
4	3-Yr Average of Net Write Off Rate								0.3688357%
5									
6	Test Period Revenues			$	555,198,613	$	555,198,613		
7									
8	PROFORMA BAD DEBT RATE						0.3688357%		
9	PROFORMA BAD DEBTS					$	2,047,771		
10									
11	UNCOLLECTIBLES CHARGED TO EXPENSE IN TEST YEAR						2,915,209		
12	INCREASE (DECREASE) EXPENSE							$	(867,438)
13									
14	INCREASE (DECREASE) FIT						35%		303,603
15	INCREASE (DECREASE) NOI							$	563,835

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PUGET SOUND ENERGY-GAS
MISCELLANEOUS OPERATING EXPENSE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	ACTUAL	RESTATED / PROFORMA	ADJUSTMENT
1	OPERATING EXPENSES (RESTATED)			
2				
3	INCENTIVE/MERIT PAY	$ 1,386,483	$ 1,233,646	$ (152,837)
4	PAYROLL TAXES ASSOC WITH MERIT PAY	97,054	86,355	(10,699)
5				
6				
7				
8				
9	INCREASE (DECREASE) IN EXPENSE	$ 1,483,537	$ 1,320,001	$ (163,536)
10				
11	INCREASE(DECREASE) INCOME			163,536
12	INCREASE(DECREASE) FIT @		35%	57,238
13				
14	INCREASE(DECREASE) NOI			$ 106,298
15				
16				
17	RATEBASE			
18	CWIP "IN SERVICE" BUT NOT TRANSFERRED TO PLANT			3,267,546
19				
20				
21	TOTAL ADJUSTMENT TO RATEBASE			$ 3,267,546

PUGET SOUND ENERGY-GAS
PROPERTY TAXES
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT
1	RESTATED PROPERTY TAX		$ 11,663,800
2	CHARGED TO EXPENSE IN TY		10,403,002
3	INCREASE(DECREASE) EXPENSE		$ 1,260,798
4			
5	INCREASE(DECREASE) FIT @	35%	(441,279)
6	INCREASE(DECREASE) NOI		$ (819,519)

PUGET SOUND ENERGY-GAS
EXCISE TAX & FILING FEE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			AMOUNT
1	**RESTATED EXCISE TAXES**		$	21,586,382
2	CHARGED TO EXPENSE FOR TEST YEAR			21,514,016
3	INCREASE(DECREASE) EXCISE TAX		$	72,367
4				
5	**RESTATED WUTC FILING FEE**		$	1,052,559
6	CHARGED TO EXPENSE FOR TEST YEAR			946,087
7	INCREASE(DECREASE) WUTC FILING FEE		$	106,472
8				
9	INCREASE(DECREASE) OPERATING EXPENSE		$	178,839
10				
11	INCREASE(DECREASE) FIT	35%	$	(62,594)
12	INCREASE(DECREASE) NOI		$	(116,245)

PUGET SOUND ENERGY-GAS
RATE CASE EXPENSES
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			AMOUNT
1	**2001 GRC EXPENSE BALANCE @ 9/30/03**		$	1,886,481
2	LESS PROJECTED AMORTIZATION FROM 10/01/03-2/28/05			(851,326)
3	REMAINING BALANCE @ 02/28/2005			1,035,155
4				
5				
6				
7	**PROFORMA 2004 RATE CASE EXPENSE:**			
8				
9	OUTSIDE SERVICE-PROFESSIONAL			766,959
10	OUTSIDE SERVICE-LEGAL			707,347
11	OTHERS			53,117
12	TOTAL PROFORMA 2004 RATE CASE EXPENSE			1,527,422
13				
14	AMOUNT TO BE AMORTIZED OVER 3 YEARS		$	2,562,578
15				
16	ANNUAL AMORTIZATION OVER 3 YEARS		$	854,193
17	LESS TEST YEAR AMORTIZATION @ $50,078/MONTH			(600,936)
18				
19	INCREASE (DECREASE) EXPENSE		$	253,257
20				
21	INCREASE(DECREASE) FIT @	35%	$	(88,640)
22	INCREASE(DECREASE) NOI		$	(164,617)

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PUGET SOUND ENERGY-GAS
PROPERTY & LIABILITY INSURANCE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	ACTUAL	PROFORMA	ADJUSTMENT
1	**PROPERTY INSURANCE EXPENSE**	$ 545,743	$ 417,176	$ (128,567)
2	**LIABILITY INSURANCE EXPENSE**	588,824	905,798	316,974
3	INCREASE(DECREASE) EXPENSE	$ 1,134,567	$ 1,322,974	$ 188,407
4				
5				
6	INCREASE (DECREASE) FIT @	35%		(65,942)
7	INCREASE (DECREASE) NOI			$ (122,465)

PUGET SOUND ENERGY-GAS
PENSION PLAN
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		ACTUAL		RESTATED		ADJUSTMENT
1	QUALIFIED RETIREMENT FUND	$	(3,427,963)	$	1,616,611	$	5,044,574
2	SERP PLAN	$	1,421,696	$	1,164,056	$	(257,640)
3							
4	INCREASE(DECREASE) EXPENSE	$	(2,006,267)	$	2,780,667	$	4,786,934
5							
6							
7	INCREASE (DECREASE) FIT @		35%				(1,675,427)
8	INCREASE (DECREASE) NOI					$	(3,111,507)

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PUGET SOUND ENERGY-GAS
WAGE INCREASE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION			TEST YEAR	RATE YEAR	ADJUSTMENT
1	WAGES:					
2	PRODUCTION MANUF. GAS			$ 111,843	$ 119,013	$ 7,169
3	OTHER GAS SUPPLY			325,936	346,828	20,892
4	STORAGE, LNG T&G			14,424	15,348	925
5	TRANSMISSION			227,477	242,059	14,581
6	DISTRIBUTION			13,727,665	14,607,608	879,943
7	CUSTOMER ACCTS			5,540,056	5,895,174	355,118
8	CUSTOMER SERVICE			554,179	589,701	35,523
9	SALES			493,368	524,993	31,625
10	ADMIN. & GENERAL			7,671,801	8,163,564	491,762
11	TOTAL WAGE INCREASE			28,666,749	30,504,288	1,837,539
12						
13	PAYROLL TAXES			2,400,320	2,566,257	165,938
14	TOTAL WAGES & TAXES			$ 31,067,069	$ 33,070,546	$ 2,003,476
15						
16	INCREASE (DECREASE) OPERATING EXPENSE					$ 2,003,476
17	INCREASE (DECREASE) FIT	@	35%			(701,217)
18	INCREASE (DECREASE) NOI					$ (1,302,260)

PUGET SOUND ENERGY-GAS
INVESTMENT PLAN
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT
1	MANAGEMENT (INC. EXECUTIVES)		
2	INVESTMENT PLAN APPLICABLE TO MANAGEMENT		$1,450,278
3	RATE YEAR MANAGEMENT WAGE INCREASE	5.34%	77,445
4	TOTAL COMPANY CONTRIBUTION FOR MANAGEMENT		1,527,723
5			
6	UNION		
7	INVESTMENT PLAN APPLICABLE TO UNION		692,133
8	RATE YEAR UNION WAGE INCREASE	7.88%	54,540
9	TOTAL COMPANY CONTRIBUTION FOR UNION		746,673
10			
11	TOTAL		
12	TOTAL PROFORMA COSTS (LN 4 + LN 9)		2,274,396
13	PRO FORMA COSTS APPLICABLE TO OPERATIONS	67.91%	1,544,542
14	CHARGED TO EXPENSE FOR YEAR ENDED 9/30/2003		1,454,911
15	INCREASE (DECREASE) EXPENSE		89,631
16			
17	INCREASE (DECREASE) FIT @	35%	(31,371)
18	INCREASE (DECREASE) NOI		($58,260)

PUGET SOUND ENERGY-GAS
EMPLOYEE INSURANCE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT
1	BENEFIT CONTRIBUTION:		
2	SALARIED EMPLOYEES		$ 2,899,921
3	UNION EMPLOYEES		3,076,363
4	PRO FORMA INSURANCE COSTS		5,976,284
5			
6	APPLICABLE TO OPERATIONS @	67.73%	4,047,737
7	CHARGED TO EXPENSE 09/30/03		3,337,843
8	INCREASE(DECREASE) EXPENSE		709,894
9			
10	INCREASE(DECREASE) FIT @	35%	(248,463)
11			
12	INCREASE(DECREASE) NOI		$ (461,431)

PUGET SOUND ENERGY-GAS
LOW INCOME AMORTIZATION
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		AMOUNT
1	AMORTIZATION FOR TEST YEAR		$ 2,757,235
2			
3			
4	INCREASE (DECREASE) NOI		$ 2,757,235
5			
6	INCREASE(DECREASE) FIT @	35%	965,032
7			
8	INCREASE(DECREASE) NOI		$ 1,792,203

PUGET SOUND ENERGY-GAS
GAS WATER HEATER & CONVERSION BURNER RENTAL PROGRAM
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.			ADJUSTMENT
1	GAS WATER HEATER & CONVERSION BURNER RENTAL PROGRAM		
2			
3	OPERATING EXPENSES:		$ -
4	O&M		-
5	DEPRECIATION EXPENSE		-
6	TOTAL DECREASE TO OPERATING EXPENSE		
7		35.00%	-
8	FEDERAL INCOME TAX:		
9			$ -
10	NET CHANGE TO OPERTING INCOME		
11			
12			
13	RATE BASE:		
14	DEPRECIABLE PROPERTY	$ -	
15	LESS: ACCUMULATED DEPRECIATON	-	
16	LESS: DEFERRED FIT	-	$ -
17	REDUCTION TO RATE BASE		
18			

PUGET SOUND ENERGY-GAS
GENERAL RATE INCREASE
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	
1	RATE BASE	$ 1,068,303,689
2	RATE OF RETURN	9.12%
3		
4	OPERATING INCOME REQUIREMENT	97,429,296
5		
6	PRO FORMA OPERATING INCOME	69,893,933
7	OPERATING INCOME DEFICIENCY	27,535,363
8		
9	CONVERSION FACTOR	59.62063%
10	REVENUE REQUIREMENT DEFICIENCY	46,184,288
11	MISCELLANEOUS SETTLEMENT ADJUSTMENT	
	TOTAL REVENUE REQUIREMENT	$46,184,288
12		

PUGET SOUND ENERGY-GAS
PRO FORMA COST OF CAPITAL
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	PRO FORMA CAPITAL %	COST %	COST OF CAPITAL
1	DEBT	54.96%	6.96%	3.83%
2	PREFERRED	0.04%	8.51%	0.00%
3	EQUITY	45.00%	11.75%	5.29%
4	TOTAL	100.00%		9.12%
5				
6	AFTER TAX DEBT (LINE 1 * 65%)	54.96%	4.52%	2.49%
7	PREFERRED	0.04%	8.51%	0.00%
8	EQUITY	45.00%	11.75%	5.29%
9	TOTAL AFTER TAX COST OF CAPITAL	100.00%		7.78%

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PUGET SOUND ENERGY-GAS
CONVERSION FACTOR
FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2003
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	BASE	RATE	AMOUNT
1	TOTAL OPERATING REVENUE			100%
2				
3	OPERATING REVENUE DEDUCTION			
4	OTHER OPERATIONS			0.369%
5	OTHER TAXES			
6	STATE UTILITY	100.00%		
7		-0.369%		
8				
9	STATE UTILITY TAX	99.63%	3.852%	3.837792%
10	MUNICIPAL REVENUE			3.879320%
11	ALL OTHER (FILING FEE)			0.190000%
12	FEDERAL INCOME TAX:			
13	CURRENT	91.72%	35.00%	32.10%
14				
15				
16	TOTAL OPERATING REVENUE DEDUCTIONS			40.379%
17				
18	CONVERSION FACTOR			59.6206%

Exhibit No. ______ (JHS-E9)

Puget Sound Energy
Allocation Methods
For Twelve Months Ended September 30, 2003

Method	Description		Electric	Gas	Total
	* 12 Month Average Number of Customers	9/30/2003	963,664	628,082	1,591,746
1	Percent		60.54%	39.46%	100.00%
	* Joint Meter Reading Customers	9/30/2003	619,724	332,671	952,395
2	Percent		65.07%	34.93%	100.00%
	* Non-Production Plant				
	Distribution	9/30/2003	$ 2,504,397,382	$ 1,475,499,325	$ 3,979,896,708
	Transmission	9/30/2003	274,609,259	98,770,380	373,379,640
	Direct General Plant	9/30/2003	136,210,907	50,818,388	187,029,295
	Total		$ 2,915,217,549	$ 1,625,088,093	$ 4,540,305,642
3	Percent		64.21%	35.79%	100.00%
	* 4-Factor Allocator				
	Number of Customers	9/30/2003	963,664	628,082	1,591,746
	Percent		60.54%	39.46%	100.00%
	Labor - Direct Charge to O&M	9/30/2003	$ 28,154,990	$ 14,311,924	$ 42,466,914
	Percent		66.30%	33.70%	100.00%
	T&D O&M Expense (Less Labor)	9/30/2003	$ 41,897,721	$ 11,543,859	$ 53,441,580
	Percent		78.40%	21.60%	100.00%
	Net Classified Plant (Excluding General Plant)	9/30/2003	$ 2,321,603,082	$ 1,105,973,344	$ 3,427,576,426
	Percent		67.73%	32.27%	100.00%
	Total Percentages		272.97%	127.03%	400.00%
4	Percent		68.24%	31.76%	100.00%
	* Labor				
	Benefit Assessment Distribution	9/30/2003	$ 5,944,648	$ 3,322,937	$ 9,267,585
	Total		$ 5,944,648	$ 3,322,937	$ 9,267,585
5	Percent		64.14%	35.86%	100.00%
	* Current & Deferred FIT	9/30/2003	$ 52,079,273	$ 8,822,100	$ 60,901,373
6	Percent		85.51%	14.49%	100.00%

Puget Sound Energy
Gas Rate Base
As of September 30, 2003

Electric	68.24%
Gas	31.76%

Line No.	Description	AMA 12 Months Ended 9/30/2003
	(a)	(j)
1	Gas Utility Plant in Service	1,634,697,162
2	Common Plant-Allocation to Gas	117,570,891
3	Gas Stored Underground - Non current	3,246,534
4	Total Plant in Service and Other Assets	1,755,514,587
5	Accumulated Provision for Depreciation	(504,330,522)
7	Common Accumulated Depreciation-Allocation to Gas	(36,476,714)
8	Customer Advances for Construction	(17,174,520)
9	Contributions in Aid of Construction - Accum. Def. FIT.	-
10	Working Capital Adjustments (Working Capital, Line 78)	5,855,343
11	Liberalized Depreciation Total Accum. Def. FIT - Liberalized **	(140,198,298)
12	Accumulated Depreciation and Other Liabilities	(692,324,712)
13	Net Operating Investment	1,063,189,875
14	Allowance for Working Capital	1,966,924
15	Total Gas Rate Base	$ 1,065,156,799

**Year-end balance, all others are average-of-monthly-average balances.

Puget Sound Energy
Gas Allowance For Working Capital
Average-of-the-Monthly-Averages for the Thirteen-Month Period Ended September 30, 2003

	Allocation factor	Tax factor
Electric	68.24%	65.51%
Gas	31.76%	[redacted]

Line No.		Company Supplemental 12 Months Ended 9/30/2003-AMA	Staff Adjustments	Staff Working Capital	Company Adjustments	Company Rebuttal 12 Months Ended 9/30/2003-AMA
	Average Invested Capital					
1	Debt	2,139,218,633		2,139,218,633		2,139,218,634
2	Less:Debt Discount and Expense	(33,432,334)		(33,432,334)		(33,432,332)
3	Compensating Balance Requirements	-		-		3
4	Net Debt	2,105,786,299		2,105,786,299		2,105,786,303
5	Preferred Stock	381,901,588		381,901,588		381,901,593
6	Investment Tax Credit	3,865,613		3,865,613		3,865,619
7	Common Equity	1,419,616,036		1,419,616,036		1,419,616,043
8	Total Invested Capital	3,911,169,536		3,911,169,536		3,911,169,558
	Average Investment					
	Gas Operating:					
9	Gas Utility Plant in Service	1,634,697,162		1,634,697,162		1,634,697,162
10	Plus:Software in Service Reclassified	-		-		-
11	Gas Completed Work Not Classified	-		-		-
12	Plus:Paving in Service Reclassified	-		-		-
13	Gas Stored Underground, Non-Current	3,246,534		3,246,534		3,246,534
14	Gas Accumulated Depreciation	(504,330,522)		(504,330,522)		(504,330,522)
15	Gas Customer Advances for Construction	(17,174,520)		(17,174,520)		(17,174,520)
16	Gas Contributions in Aid of Construction	-		-		-
17	Gas Deferred Federal Income Tax	(187,428,993)	(23,359,358)	(210,788,351)	6,004,633	(181,424,360)
18	Less:Deferred tax - Regulatory Tax Liabiltiy	-		-		-
19	ADIT SFAS 109	(18,410,392)		(18,410,392)		(18,410,392)
20	DSM & Environmental	4,658,977		4,658,977		4,658,977
21	Other Utility ADIT	28,698,080		28,698,080		28,698,080
22	Restating and Pro Forma Adjustments	-		-		-
22	Average Gas Operating Investment-Direct	943,956,326		920,596,968		949,960,959
23	Common Plant-Allocation to Gas	117,570,891		117,570,891		117,570,891
23a	Investment in Assoc Company - Rainier Receivables	4,167,953		4,167,953		4,167,953
24	Common Accumulated Depreciation-Allocation to Gas	(36,476,714)		(36,476,714)		(36,476,714)
25	Average Common Operating Invest-Allocation to Gas	85,262,130		85,262,130		85,262,130
26	Total Average Gas Operating Investment	1,029,218,456		1,005,859,098		1,035,223,089
	Non Operating:					
28	Construction Work in Progress	28,009,840		28,009,840		28,009,840
29	Common Construct Work in Progress-Alloc to Gas	3,949,221		3,949,221		3,949,221
30	Less:Software in Service Reclassified	-		-		-
31	Intercompany Accounts -net	3,600,500		3,600,500		3,600,500
32	Merchandising Receivable -net	(7,129,436)		(7,129,436)		(7,129,436)
33	Investment related deferred debits	113,182,867		113,182,867		113,182,867
34	Less:Paving in Service Reclassified	-		-		-
35	DSM & Environmental	(4,658,977)		(4,658,977)		(4,658,977)
36	Environmental Remediation - Deferred Credits	-		-		-
37	Environmental remediation - Accounts Receivable	-		-		-
38	Environmental Remediation - Accounts Payable	-		-		-
39	Gas Regulatory Asset SFAS 109	10,287,688		10,287,688		10,287,688
40	Gas Regulatory Liability SFAS 109	-		-		-
41	ADIT SFAS 109	18,410,392		18,410,392		18,410,392
42	Less Other Utility ADIT	(28,698,080)		(28,698,080)		(28,698,080)
43	Merchandising Inventory	79,012		79,012		79,012
44	Deferred Purchased Gas Costs - Accounts Rec'ble	(48,814,356)		(48,814,356)		(48,814,356)
45	Deferred Purchased Gas Costs - Accounts Payable	-		-		-
46	Misc. Reserves for Deferred Dr's - Accounts Receivable	-		-		-
47	Deferred SERP - Current Liabilities	(17,458,742)		(17,458,742)		(17,458,742)
48	Deferred Severence - Current Liabilities	(4,422)		(4,422)		(4,422)
49	Gas Premilinary Work	-		-		-
50	Electric Plant in Service	4,136,698,847		4,136,698,847		4,136,698,847
50a	Common Current Accounts-Electric Share	(71,499,794)	7,131,660	(64,368,134)	7,131,660	(64,368,134)
50b	Electric Current Accounts	(15,064,008)		(15,064,008)		(15,064,008)
51	Common Plant-Allocation to Electric	252,614,535		252,614,535		252,614,535

Puget Sound Energy
Gas Allowance For Working Capital
Average-of-the-Monthly-Averages for the Thirteen-Month Period Ended September 30, 2003

	Allocation factor	Tax factor
Electric	68.24%	85.51%
Gas	31.76%	[redacted]

Line No.		Company Supplemental 12 Months Ended 9/30/2003-AMA	Staff Adjustments	Staff Working Capital	Company Adjustments	Company Rebuttal 12 Months Ended 9/30/2003-AMA
52	Electric Future Use Property	6,772,284		6,772,284		6,772,284
53	Common Future Use Property-Allocation to Electric	-		-		-
54	Customer Advances for Construction	(23,664,861)		(23,664,861)		(23,664,861)
55	Customer Deposits	(8,752,784)		(8,752,784)		(8,752,784)
56	Deferred Taxes	(410,867,797)	23,359,358	(387,508,439)	(6,004,633)	(416,872,430)
57	Deferred Debits - Other	95,909,633	2,044,654	97,954,287		95,909,633
58	Less: Electric Accumulated Depreciation	(1,736,314,290)		(1,736,314,290)		(1,736,314,290)
59	Less: Common Accum Depr-Allocation to Electric	(78,374,401)		(78,374,401)		(78,374,401)
60	Electric Completed Const. Not Classified	-		-		-
61	Conservation Investment	154,506		154,506		154,506
62	Other & FAS 133	649,197,861		649,197,861		649,197,861
63	Total Non Operating & Electric Plant Investment	2,867,565,238		2,900,100,910		2,868,692,265
	Total Average Net Investment	3,896,783,694		3,905,960,008		3,903,915,354
64	Total Investor Supplied Working Capital	14,385,842		5,209,528		7,254,204
	Total Average Investments	3,896,783,694		3,905,960,008		3,903,915,354
	Less: Gas CWIP	(31,959,061)		(31,959,061)		(31,959,061)
	Other work in progress					
	Preliminary surveys	-		-		-
	Total	3,864,824,633		3,874,000,947		3,871,956,293
65	Working Capital %	0.37%		0.13%		0.19%
66	Utility Allowance	3,808,108		1,307,617		1,966,924

Line	Acct	Descr	Alloc	Working Capital Amt	Rate Base Amt
67					
68					
69	Non Operating to Working Capital				
70		14209993 Cust A/R Clrng CLX	31.76%	(7,131,660)	
71	Non Operating to Operating				
72		19000012 Accum Def Inc Tax-Gas	100%	46,778,090	48,572,715
73		28300023 Def Tax CLX Amort	31.76%	(84,614)	(252,810)
74		28300193 Def Inc Tax-SAP	31.76%	(1,911,132)	(2,240,350)
75		28300501 IRS Carryover Adj-CLX	31.76%	(9,205,874)	(10,579,891)
76				35,576,470	
77		28300513 Indirect Cost Adjustment	40.85%	(29,571,837)	(29,644,321)
78				6,004,633	5,855,343

Appendix C

Puget Sound Energy
2004 General Rate Case, UE-040641 & UG-040640
Comparison of Parties' Positions
Restating Actual and Pro Forma Adjustments - Electric
12 Months Ending September 30, 2003

Adjustment	Line No.	Description	Company	Staff
	1	NOI - Actual	$ 219,638,434	$ 219,638,434
		Uncontested Adjustments		
2.01	2	Temperature Normalization	$ 4,374,555	$ 4,374,555
2.02	3	General Revenues	116,919,193	116,919,193
2.05	4	Federal Income Taxes	(4,651,347)	(4,651,347)
2.07	5	Depreciation/Amortization	(97,252)	(97,252)
2.08	6	Conservation	26,189,031	26,189,031
2.09	7	Bad Debts	961,153	961,153
2.12	8	White River	(73,280)	(73,280)
2.13	9	Filing Fee	(143,538)	(143,538)
2.14	10	D&O Insurance	5,175	5,175
2.15	11	Montana Energy Tax	(107,925)	(107,925)
2.16	12	Interest on Customer Deposits	(151,631)	(151,631)
2.17	13	SFAS 133	555,963	555,963
2.19	14	Property Sales	(2,918,307)	(2,918,307)
2.21	15	Pension Plan	(5,565,312)	(5,565,312)
2.24	16	Employee Insurance	(825,326)	(825,326)
2.26	17	Storm Damage	366,405	366,405
2.27	18	Frederickson Plant	(2,684,243)	(2,684,243)
2.28	19	Low Income Amortization	3,801,853	3,801,853
	20	Total Uncontested Adjustments	$ 135,955,167	$ 135,955,167
		Contested Adjustments		
2.03	21	Power Costs	$ (58,730,987)	$ (63,315,425)
2.04	22	Sale for Resale	(113,651,741)	(95,699,399)
2.06	23	Tax Benefit of Proforma Interest	(9,337,425)	(7,530,496)
2.10	24	Miscellaneous Operating Expense	(1,573,174)	(98,086)
2.11	25	Property Taxes	1,679,813	2,510,356
2.18	26	Rate Case Expense	(157,991)	123,736
2.20	27	Property & Liability Insurance	(321,615)	(232,606)
2.22	28	Wage Increase	(2,509,848)	(1,894,612)
2.23	29	Investment Plan	(104,205)	(74,901)
2.25	30	Montana Corp. License Tax	(1,283,057)	(1,272,865)
2.30	31	Production Adjustment	546,289	540,136
	32	Total Contested Adjustments	$ (185,443,942)	$ (166,944,162)
	33	NOI - Adjusted	$ 170,149,659	$ 188,649,439

Puget Sound Energy
2004 General Rate Case, UE-040641 & UG-040640
Comparison of Parties' Positions
Restating Actual and Pro Forma Adjustments - Electric
12 Months Ending September 30, 2003

Adjustment	Line No.	Description	Company	Staff
	1	Rate Base - Actual	$ 2,516,697,113	$ 2,515,307,703
		Uncontested Adjustments		
2.07	2	Depreciation/Amortization	$ (74,810)	$ (74,810)
2.08	3	Conservation	(11,569,864)	(11,569,864)
2.10	4	Miscellaneous Operating Expense	1,711,055	1,711,055
2.12	5	White River	19,837,623	19,837,623
2.27	6	Frederickson Plant	75,444,529	75,444,529
2.29	7	Regulatory Assets	(46,237,863)	(46,237,863)
2.30	8	Production Adjustment	(9,748,332)	(9,748,332)
	9	Total Uncontested Adjustments	$ 29,362,338	$ 29,362,338
		Contested Adjustments		
	10		$ -	$ -
	11	Total Contested Adjustments	$ -	$ -
	12	NOI - Adjusted	$ 2,546,059,451	$ 2,544,670,041

Appendix D

Puget Sound Energy
2004 General Rate Case, UE-040641 & UG-040640
Comparison of Parties' Positions
Restating Actual and Pro Forma Adjustments - Gas
12 Months Ending September 30, 2003

Adjustment	Line No.	Description	Company	Staff
	1	NOI - Actual	$ 81,455,387	$ 81,455,387
		Uncontested Adjustments		
2.02	2	Federal Income Tax	$ (1,221,100)	$ (1,221,100)
2.04	3	Depreciation/Amortization	(156,853)	(156,853)
2.05	4	Conservation	754,507	754,507
2.06	5	Bad Debt	563,835	563,835
2.08	6	Property Taxes	(819,519)	(819,519)
2.09	7	Filing Fee	(116,245)	(116,245)
2.12	8	Pension Plan	(3,111,507)	(3,111,507)
2.15	9	Employee Insurance	(461,431)	(461,431)
2.16	10	Low Income Amortization	1,792,203	1,792,203
	11	Total Uncontested Adjustments	$ (2,776,110)	$ (2,776,110)
2.01	12	Revenue & Purchased Gas	(1,236,133)	1,110,277
2.03	13	Tax Benefit of Proforma Interest	(6,007,908)	(5,700,092)
2.07	14	Miscellaneous Operating Expense	106,298	635,846
2.10	15	Rate Case Expenses - **See Note**	(164,617)	(164,617)
2.11	16	Property & Liability Ins	(122,465)	(81,039)
2.13	17	Wage Increase	(1,302,260)	(982,842)
2.14	18	Investment Plan	(58,260)	(41,872)
2.17	19	Gas Water Heater Program	-	606,509
	20	Total Contested Adjustments	$ (8,785,345)	$ (4,617,830)
	21	NOI - Adjusted	$ 69,893,932	$ 74,061,447

Note: Though there is no difference in the amounts, there is an issue on how rate case costs should be recovered.

Puget Sound Energy
2004 General Rate Case, UE-040641 & UG-040640
Comparison of Parties' Positions
Restating Actual and Pro Forma Adjustments - Gas
12 Months Ending September 30, 2003

Adjustment	Line No.	Description	Company	Staff
	1	Rate Base - Actual	$ 1,065,156,799	$ 1,064,535,666
		Uncontested Adjustments		
2.04	2	Depreciation/Amortization	$ (120,656)	$ (120,656)
2.07	3	Miscellaneous Operating Expense	3,267,546	3,267,546
	4	Total Uncontested Adjustments	$ 3,146,890	$ 3,146,890
		Contested Adjustments		
2.17	5	Gas Water Heater Program	$ -	$ (31,312,542)
	6	Total Contested Adjustments	$ -	$ (31,312,542)
	7	NOI - Adjusted	$ 1,068,303,689	$ 1,036,370,014