[Service Date January 5, 2007]

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND	)	
TRANSPORTATION COMMISSION,	)	DOCKETS UE-060266 and
	)	UG-060267 (*consolidated)*
Complainant,	)	
v.	)	ORDER 08
	)	
PUGET SOUND ENERGY, INC.,	)	REJECTING TARIFF SHEETS;
	)	AUTHORIZING AND REQUIRING
Respondent.	)	COMPLIANCE FILING
. . . .	)	

Synopsis*: The Commission rejects revised tariff sheets Puget Sound Energy, Inc. (PSE or the Company), filed on February 15, 2006, but authorizes and requires the Company to file tariff sheets that will result in increases of about 1.0 percent for electric rates and 3.2 percent for natural gas rates, which are found on the record of this proceeding to be fair, just, reasonable and sufficient. The Commission rejects PSE's, and others' proposals to implement novel mechanisms that would shift disproportional risks to customers. The record does not demonstrate that such programs are necessary for the Company, beneficial for customers, or in the public interest. The Commission approves a pilot, incentive-based program to promote electric conservation and increased funding for low-income assistance programs.*

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SUMMARY

1 **PROCEEDINGS:** On February 15, 2006, Puget Sound Energy, Inc. (PSE), filed revisions to its electric tariff as required by the Commission's Order 04 in Docket UE-050870, the Company's 2005 PCORC (power cost only rate case).[1] PSE also filed revisions to its natural gas tariff. The revisions proposed a general rate increase of $148.8 million, or 9.21 percent for electric service and $51.3 million, or 5.34 percent for gas service. The Commission suspended the proposed tariff revisions on February 18, 2006, prior to their stated effective date of March 18, 2006.

2 PSE adjusted its request via supplemental testimony filed on July 7, 2006, taking into account the Company's updated base power costs approved in Docket UE-060783, a periodic Power Cost Adjustment (PCA) proceeding, and other factors. The Company based its revised proposal on an asserted electric revenue deficiency of $42.9 million and an asserted natural gas revenue deficiency of $39.2 million.

3 On July 19, 2006, Staff, Public Counsel and the intervening parties filed their respective response testimonies. Staff opposed the Company's request for increased revenue and, based on its responses concerning cost of capital and other matters, recommended a $40.7 million reduction from currently approved annual electricity revenue and a $19.3 million increase in annual natural gas revenue. Public Counsel, ICNU and other parties sponsored various ratemaking adjustments and presented evidence on several policy matters. Staff, however, is the only party opposing PSE that presented a full revenue requirement recommendation.

4 On rebuttal, filed August 23, 2006, PSE further reduced its asserted electric revenue deficiency to $33.8 million (1.97 percent) and its request for added natural gas revenue to $39.0 million (4.06 percent), taking into account certain adjustments proposed by others in their response cases and agreed to by the Company. On September 15, 2006, PSE and Staff stipulated to a number of revenue requirement adjustments. As a result, the Company again adjusted its request for additional revenue down to $33.5 million for electric and $38.9 million for natural gas. Staff adjusted its recommended electric revenue decrease to

[1] A glossary of acronyms and terms is attached for the convenience of readers.

($31.9) million and adjusted its recommended natural gas revenue increase to $20.5 million. Table 1 summarizes the final levels of adjustment to annual revenue proposed by the two parties who put on full revenue requirement cases.

TABLE 1

Proposed Total Adjustments to Annual Base Rates
Revenue Requirement ($M) Relative to Current Rates[2]

	As-Filed[3]	Supplemental	Response	Rebuttal	Stipulation
Electric:					
PSE	$140.9	$42.9		$33.8	$33.5
Staff			($41.0)		($31.9)
Natural Gas:					
PSE	$40.4	$39.2		$39.0	$38.9
Staff			$19.6		$20.5

5 The Commission, having suspended the tariff filing by order entered on February 22, 2006, conducted a public comment hearing in Renton, Washington on June 29, 2006, and evidentiary hearings in Olympia, Washington, on September 18 - 21 and 25, 2006. The parties filed Initial Briefs on October 31, 2006, and Reply Briefs on November 14, 2006. This order resolves all remaining contested issues.

6 **PARTY REPRESENTATIVES:** Kirstin S. Dodge, Sheree S. Carson and Jason Kuzma, Perkins Coie, Bellevue, Washington, represent PSE. Simon ffitch, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington Office of Attorney General (Public Counsel). Robert D. Cedarbaum, Senior Assistant Attorney General, Olympia, Washington, represents the Commission's regulatory staff (Commission Staff or Staff).[4]

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[2] Excludes any adjustment related to proposals for post-test year additions to rate base suggested as alternatives to PSE's proposed depreciation tracker mechanism.

[3] According to PSE's cover letter transmitting the Company's initial filing on February 15, 2006, the electric revenue request was $148.8 million and the gas revenue request was $51.3. See also Exhibit 171 (Harris Direct) at 6:11-12. The lower figures in this column are taken from Exhibit 421 (Story Direct) at 2:7-9, Exhibit 431 (Story Supplemental) at 2:3-6, Exhibit 222 (Karzmar Direct) at 2:3-5 and Exhibit 228 (Karzmar Supplemental) at 1:15-17.

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

7 S. Bradley Van Cleve, Matthew W. Perkins, and Irion Sanger, Davison Van Cleve, Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Michael L. Kurtz and Kurt J. Boehm, Boehm, Kurtz & Lowry, Cincinnati, Ohio, represent the Kroger Co., on behalf of its Fred Meyer Stores and Quality Food Centers divisions (Kroger). Elaine L. Spencer, Graham & Dunn PC, Seattle, Washington, represents Seattle Steam Company (Seattle Steam). Norman Furuta and Rita Liotta, Department of the Navy, Daly City, California, represent the Federal Executive Agencies (FEA). Michael Alcantar and Donald Brookhyser, Alcantar & Kahl LLP, Portland, Oregon, represent the Cogeneration Coalition. Edward A. Finklea and Chad M. Stokes, Cable Huston Benedict Haagensen & Lloyd LLP, Portland, Oregon, represent Northwest Industrial Gas Users (NWIGU). Nancy Glaser, NW Energy Coalition (NWEC), represents the NWEC. John O'Rourke, Director, Citizens' Utility Alliance (CUA), represents the CUA. Ronald L. Roseman, Attorney, Seattle, Washington, represents the Energy Project.

8 **COMMISSION DETERMINATIONS**: The Commission suspended and set for hearing the rates PSE initially proposed. The Company, as summarized above, revised its as-filed proposal downward on several occasions during the pendency of these proceedings. Accordingly, the Commission has no record upon which to determine, and does not need to determine whether the Company's as-filed rates meet the statutory fair, just, reasonable and sufficient standard for approval. Rather, we must determine such rates on the basis of the record before us.[5] In this order, we evaluate PSE's final revised rate request and resolve a number of contested issues that separate the parties by more than $80 million. We also resolve several important policy issues related to risk mitigation and other matters. We summarize our determinations in Table 2.

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[5] RCW 80.28.020.

TABLE 2
Summary of Commission Determinations

REVENUE REQUIREMENT ISSUES	Commission Determination
Power Costs:	
Should gas costs be updated and AURORA rerun?	YES
Should PSE be required to use forward market electric prices to determine power costs?	NO
Should combustion turbine run times be increased and down times decreased relative to PSE AURORA model run inputs?	NO
Should hydro-shaping be adjusted to increase peak hydro relative to PSE AURORA model run inputs?	NO
Director and Officer Insurance: Should PSE's proposed allocation of premiums be rejected in favor of Staff's proposal?	NO
Rate of Return:	*Embedded Table Below*

Component	Share (%)	Cost (%)	Weighted Cost
Equity	44.13	10.4	4.59
Long-term debt	48.01	6.64	3.19
Short-term debt	2.60	6.66	0.17
Trust Preferred	5.22	8.54	0.45
Preferred	.04	7.61	0.00
Overall Rate of Return			**8.40**

RATE SPREAD / RATE DESIGN	Commission Determination
Electric: Should the Commission approve and adopt the parties' stipulation?	YES
Gas:	
What rate spread should the Commission approve?	PSE
What rate design should the Commission approve?	Joint Parties except as set forth in *Embedded Table Below*

Description	Current Customer Charge	Commission Determination
Residential (Schedule 23)	$6.25	$8.25
Commercial & General Service (Schedule 31)	$15.00	$17.50
Large Volume (Schedule 41)	$70.00	$80.00
Transportation (Schedule 57)	$800.00	$800.00
Non-exclusive Interruptible (Schedule 87)	$500.00	$500.00
Interruptible (Schedules 85 and 86)	$500.00 and $100.00	$500.00 and $100.00
PSE's proposed changes to Commercial and Interruptible Schedules 36, and 51, and Rental Schedules 71, 72, and 74 were not disputed and should be adopted.		

Policy Issues	Commission Determination
Proposed PCA Modifications Should the Commission:	
Modify deadband and/or sharing bands?	NO
Eliminate Exhibit E requirements for treatment of power costs under certain contracts?	YES
Eliminate paragraph 10 general rate case filing requirement?	NO
Allow new hedging line of credit costs?	YES
Depreciation: Should the Commission:	
Approve a depreciation tracker mechanism as proposed by PSE?	NO
Approve post-test period additions to rate base?	NO
Decoupling:	
Should the Commission approve a decoupling mechanism for natural gas rates?	NO
Electric Conservation Incentive/Penalty:	
Should the Commission approve an incentive/penalty mechanism?	YES, adopt Staff proposal for a 3-year pilot program

9 We determine that PSE should be authorized and required to file rates in compliance with our decisions, as summarized here and discussed in detail below. When implemented via the compliance filing we require the Company to make, the resulting rates will be fair, just, reasonable and sufficient, and neither unduly discriminatory nor preferential. Because we require PSE to rerun its AURORA power cost model based on updated natural gas costs, we will determine the exact revenue deficiency for electric service during the compliance phase.[6] We find a revenue deficiency of $31,259,011 for natural gas and authorize PSE to file rates to recover additional revenue in this amount.

[6] As discussed below, we require PSE to rerun the AURORA model using gas prices updated through November 30, 2006. As a point of reference, using gas prices based on forward prices for the three months ended September 30, 2006, the power cost adjustment in PSE's results of operations would be $293,563,457 (*i.e.*, NOI of ($182,224,643)). Using this as a point of reference for illustrative purposes and taking into account all other adjustments, PSE's total revenue requirement deficiency for electric would be ($2,102,237). The final revenue requirement for electric that PSE will use in making its compliance filing will be either slightly higher or lower depending on the level of power costs determined via the required rerun of AURORA. *See infra, Table 9.*

MEMORANDUM

I. Background and Procedural History

10 On February 15, 2006, PSE filed revisions to its currently effective Tariff WN U-60, Tariff G, Electric Service, and revisions to its currently effective Tariff WN U-2, Gas Service. The proposed tariff revisions bore an effective date of March 18, 2006. PSE proposed a general rate increase of 9.21 percent for the electric tariffs and 5.23 percent for the gas tariffs. The Commission suspended the proposed tariff revisions on February 22, 2006, consolidated the two dockets, and set the matters for hearing.

11 The Commission conducted a prehearing conference on March 21, 2006, before Administrative Law Judge C. Robert Wallis. On March 23, 2006, the Commission entered Order 02, granting various pending petitions to intervene, authorizing formal discovery, and establishing a procedural schedule. Administrative Law Judge Dennis J. Moss assumed responsibility as presiding officer in this proceeding during June 2006.

12 The parties prefiled extensive testimony and numerous exhibits sponsored by 35 witnesses, including 21 for PSE, 2 for Public Counsel, 4 for Staff and 8 for various intervenors. On July 25, 2006, Staff filed a proposed Rate Spread and Rate Design Settlement for electric rates. All parties whose prefiled testimony addressed these subjects supported the proposal and no party voiced opposition.

13 On September 15, 2006, Staff and PSE filed their Agreement on Revenue Requirement Adjustments. In making this filing, Staff noted that no other party had filed testimony on the issues to which Staff and PSE reached agreement.

14 The Commission held a public comment hearing in Renton, Washington during the evening of June 29, 2006, and conducted evidentiary hearings in Olympia, Washington on September 18-21 and 25, 2006. Chairman Mark H. Sidran, Commissioner Patrick J. Oshie and Commissioner Philip B. Jones were assisted at the bench by presiding Administrative Law Judge Dennis J. Moss. Altogether, the record includes more than five hundred exhibits entered during five days of evidentiary proceedings. The transcript of these proceedings is nearly 1,000 pages in length.

15 The parties filed Initial Briefs on October 31, 2006, and Reply Briefs on November 14, 2006. The Commission here enters its Final Order resolving the disputed issues, approving certain uncontested adjustments, and granting appropriate relief considering the full record of proceedings and the parties' arguments based on that record.

II. Discussion and Decisions

A. Risk Mitigation Proposals—Electric

1. Modification of Power Cost Adjustment Mechanism

16 The Commission authorized PSE to implement a power cost adjustment (PCA) mechanism during 2002 as part of a comprehensive settlement of the Company's general rate proceeding in Docket Nos. UE-011570 and UG-011571.[7] PSE now requests us to authorize four changes to the PCA mechanism, as follows:

- Eliminate the current $20 million dead band, consolidate the remaining bands, and modify the cost-sharing percentages in each band.

- Eliminate paragraph 10 of the PCA, which requires PSE to file a general rate case within three months after the conclusion of a power cost only rate case (PCORC)[8] that results in an increase to general rates.

- Eliminate Exhibit E to the PCA, which provides for asymmetrical treatment of costs associated with certain long-term power contracts and purchased power agreements for hydroelectric resources.

- Add to the Power Cost Baseline Rate the cost associated with a new line of credit to support wholesale power hedging transactions.

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[7] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-011570 & UG-011571, Twelfth Supp. Order (2002).

[8] The PCORC mechanism allows for expedited consideration between general rate proceedings of the prudence and rate treatment of costs associated with major generation acquisitions by PSE. The PCORC mechanism was also approved as part of the settlement in Docket Nos. UE-011570 & UG-011571.

We discuss below our reasons for denying PSE's first two requests and granting the second two.

a. Eliminate the current $20 million dead band, consolidate the remaining bands, and modify the cost-sharing percentages in each band.

17 The PCA currently includes a $20 million dead band within which PSE either absorbs all power costs that exceed the Power Cost Baseline Rate or retains all savings if power costs fall below the baseline. PSE shareholders and ratepayers share excess costs or savings greater than $20 million, as shown in Table 3. PSE proposes in this proceeding the PCA cost sharing bands shown in Table 4.

TABLE 3

Current PCA Sharing Bands

Power Costs ($ in millions) (over or under the PCA baseline)	Customers' Share	Shareholders' Share
$0 - $20 +/-	0%	100%
$20 - $40 +/-	50%	50%
$40 - $120 +/-	90%	10%
> $120 +/-	95%	5%

TABLE 4

Proposed PCA Sharing Bands

Power Costs ($ in millions) (over or under the PCA baseline)	Customers' Share	Shareholders' Share
$0 - $25 +/-	50%	50%
$25 - $120 +/-	90%	10%
> $120 +/-	95%	5%

PSE argues the current PCA mechanism exposes the Company to a significant amount of uncontrollable hydro risks—in two years out of three, hydro variability would increase or decrease power costs by up to $25 million, according to PSE.[9]

[9] PSE Initial Brief ¶25 (citing Aladin, Exhibit 11C at 20:3-15).

The Company argues that such variations cannot be controlled regardless of how well PSE manages its electric portfolio overall.[10]

18 Although hydro risk is indeed variable, the current PCA adequately addresses this risk by providing for deferral and amortization of excess power costs associated with hydro variations.[11] Moreover, we expect hydro variability will be reasonably balanced over time. While below normal hydro may result in excess power costs in some years, this will be offset during other periods when hydro is more abundant.

19 Again focusing on the subject of risk sharing, PSE argues that the expiration earlier this year of a $40 million cumulative cap on the Company's power cost exposure under the PCA will result in "a huge amount of extreme power cost risk…shifted onto PSE going forward, unless the Commission approves modification of the PCA Mechanism in this case."[12] This argument depends on a distorted perspective on the relationship of the various components of the PCA. The Commission approved in 2002 the balance of risks inherent in the dead band and the sharing bands, and also approved the $40 million cap as a means to temporarily mitigate risk to the Company so that it could improve its financial condition over a period of years. That is, the fundamental balance of risks under the PCA was temporarily tilted in PSE's favor by the $40 million cumulative cap considering the Company's distressed financial circumstances in the wake of the western energy crisis. Expiration of the cumulative cap was a feature of the PCA mechanism from the outset and cannot now be claimed to result in an unanticipated shift of risks to the Company. Instead, its expiration allows the balance of risk the Commission approved in 2002 to come fully into play for the first time.

20 PSE's proposal in this proceeding, by contrast, would result in a substantial transfer of risk from PSE to ratepayers without a corresponding ratepayer benefit. A central purpose of the PCA the Commission approved for PSE, and similar mechanisms approved or considered for other companies, is to protect the companies against extreme variations in power costs caused by such factors as the extraordinary market events that occurred during 2001 and 2002, serious drought,

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[10] *Id*.
[11] Exhibit 599 at 23:20 – 24:5 (Joint PCA).
[12] PSE Initial Brief ¶30.

or other circumstances that are beyond the companies' ability to foresee and control. PSE, in its proposal, seeks to modify the mechanism to share with customers the risk of normal variations in hydropower. This would mark a new and much expanded role for the PCA. We do not find such an expanded purpose to be in the public interest.

21 Finally, we observe that a PCA designed to insulate the Company from fifty percent of the cost risk of normal variations in hydro should necessarily be accompanied by an adjustment to the return on equity. The record in this proceeding does not include substantial competent evidence upon which we might determine the magnitude of the adjustment to return on equity that would be required to account for such a reduction in risk.

22 Before leaving this topic, we address briefly PSE's argument that elimination of the dead band and a 50/50 sharing of the first $25 million of power costs variation will align each part*y's* interest to set the Power Cost Baseline Rate as close as possible to the level that is likely to be actually experienced during the rate year.[13] We do not find such an incentive necessary. The Commission has reset the Power Cost Baseline Rate on several occasions and each time it has done so on the basis of a fully developed record. The Commission's goal has been to set the baseline as close as practicable to what is likely to be experienced during the rate year. We expect that practice to continue and we also expect the parties to continue to refine the method and improve the data upon which we act.

23 We find PSE has not carried its burden to show its proposed modifications to the PCA dead band and sharing mechanism are in the public interest and therefore do not approve the Company's request.

b. Remove the rate case requirement in Paragraph 10.

24 PSE would eliminate paragraph 10 of the PCA Mechanism, which requires the Company to file a general rate case within three months of the conclusion of a PCORC that results in an increase to general rates.[14] On brief, the Company

[13] PSE Initial Brief ¶27.
[14] Paragraph 10 of the PCA provides:

> Further, if at any time after July 1, 2005 the Company shall file for a Power Cost Only review, and such filing shall result in an increase to general rates then in effect, the

asserts that given its history of two general rate cases and two PCORCs since 2002, this provision is not necessary and would result in inefficient ratemaking. PSE offers no explanation of how this "history" makes the provision unnecessary or how the requirement leads to "inefficient ratemaking."

25 PSE also argues that no party objected to the proposed revision.[15] That is not surprising given that the Company's Initial Brief appears to be the first reference in the record to the proposed elimination of this paragraph. Thus, the Joint Parties did not address this issue on brief.[16] However, on reply, the Joint Parties argue that this change should be denied on two grounds. First, they assert an absence of supporting evidence noting that PSE, as the party with the burden of proof has a duty to clearly identify and support its proposals in its testimony. In this instance, it failed to do so.

26 Second, the Joint Parties state that this paragraph provides an important safeguard to ensure an earnings review and a true-up of all costs after the occurrence of a PCORC—a single issue ratemaking mechanism.[17]

27 PSE has not supported its assertion that ratemaking efficiency will suffer if we do not approve elimination of paragraph 10 from the PCA mechanism. We reject the Company's proposal to eliminate paragraph 10. PSE is free to seek a waiver of the provision under circumstances the Company believes will improve ratemaking efficiency. An important consideration that would inform the Commission's decision to grant such a waiver would be whether there has been a very recent general rate proceeding.

c. PCA Exhibit E.

28 Exhibit E to the Company's PCA lists certain long-term contracts for power purchases from Qualifying Facilities such as March Point and Sumas. The Commission has already approved these contracts as prudent. The cost of each

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> Company shall, within three (3) months of the effective date of any rate increase resulting from such Power Cost Only review, file a general rate case. Not more than one general rate case filing in any 12 month period shall be required to comply with this requirement.

[15] PSE Initial Brief ¶13 (citing Exhibit 428C, which sets forth the Company's proposed revisions to the PCA Mechanism). The exhibit does not, however, include a proposal to eliminate paragraph 10.
[16] Public Counsel Reply Brief ¶98.
[17] *Id.* ¶¶30-32.

contract at any given time is determined during the most recent general rate case or PCORC and is included in the power cost baseline. Under the existing PCA mechanism, if actual contract costs are higher than the Exhibit E contract rate, the difference is not included in the PCA true-up. However, if actual costs are lower than the contract rate, the lower costs are reflected in the PCA true-up.[18] PSE, having agreed to this provision when the parties negotiated the PCA's terms in 2002, now argues this asymmetrical treatment is inequitable. PSE argues Exhibit E should be eliminated or modified to use the actual contract rates rather than the lower of the actual contract rate or the approved forecast rate.

29 The Joint Parties and FEA oppose eliminating Exhibit E. They assert Exhibit E was part of the original PCA's carefully balanced compromise. According to the Joint Parties, the rational for including Exhibit E in the PCA stipulation was to "…hold some costs constant that the parties know are likely to rise (such as power supply contracts), precisely because there are other costs not tracked that parties know are likely to decline. "Examples of the latter are depreciation on Colstrip and transmission plant, which tend to decrease relative to revenues in between rate cases…. Holding these items constant tends to offset the power contract costs that may tend to rise."[19] In essence, they argue because some costs that decline are not tracked in the PCA, PSE's contract cost recovery was capped by Exhibit E, ostensibly in return for allowing other power costs to rise between rate cases.[20]

30 PSE disputes the Joint Parties' contention that holding return constant was a quid pro quo for the asymmetrical treatment of these costs, stating: "The lack of rate base adjustment in the PCA Mechanism for depreciating resources is counterbalanced by other benefits provided to customers under the PCA, such as foregone revenue growth on production plant and regulatory assets."[21]

31 The Joint Parties argument that Exhibit E should be retained because it was part of a grand compromise[22] does little to support the notion that it remains good public policy five years later. We find unpersuasive the Joint Parties' argument that

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[18] Exhibit 439 (Story rebuttal) at 24:15-17.
[19] Public Counsel Reply Brief ¶36.
[20] Public Counsel Initial Brief ¶114.
[21] PSE Initial Brief ¶¶32-33.
[22] The Joint Parties appear to have ignored the settlement negotiation privilege in bringing forward their subjective rationale for Exhibit E. This led PSE to argue its own perspective in like manner. This is not appropriate practice and should not occur in testimony or on brief.

capping the cost of these contracts is a way to offset costs that are likely to decline, such as depreciation of Colstrip and transmission facilities. While depreciation lowers cost of individual assets over time, PSE's asset acquisition may result in higher overall depreciation costs.

32 We also find unpersuasive PSE's argument that Exhibit E should be eliminated principally because it is inequitable. Whatever the parties' respective subjective intentions, the fact remains that the provision was part of a comprehensive settlement to which PSE agreed.

33 We find, however, that Exhibit E should be eliminated because it is more consistent with the fundamental purpose of any PCA program. The resources in Exhibit E fall into the power cost category, they have received regulatory approval, and the variability in the cost of these resources is outside the control of the Company. These are the types of costs for which PCA mechanisms are intended and we find they should be accurately accounted for in the true-up process. Whatever the original purpose behind asymmetrical treatment of these costs may have been, we do not find that the provision on its face is one that should survive into the future.

d. Costs associated with a new line of credit to support wholesale power hedging transactions.

34 The Joint Parties do not oppose this change but assert the hedging mechanism greatly reduces PSE's risk, an issue that should be considered in developing PSE's cost of capital in the Company's next general rate proceeding. We agree both that these costs should be included in the Power Costs Baseline Rate and that their possible impact on the Company's cost of capital requirements is a subject to consider in a future proceeding. We leave it to the parties to develop in PSE's next general rate case any arguments regarding whether inclusion of hedging costs in the baseline power cost rate should affect PSE's cost of capital.

2. Depreciation Tracker.

35 PSE proposes a new regulatory mechanism to track depreciation expense for transmission and distribution investments the Company makes between general rate cases.[23] As proposed, depreciation expenses would be recovered through a surcharge added onto existing tariff schedules. The surcharge would be based on the incremental depreciation expense of natural gas and electric transmission and distribution investment over and above the depreciation expense reflected in existing rates. There would be an annual true-up. The mechanism would allow for *recovery of* investments in new plant between rate cases, but would not provide for *recovery on* the investments. As proposed, the depreciation tracker surcharge during the initial period would be $7.9 million for electricity and $10.9 million for natural gas.

36 PSE argues it needs the depreciation tracker to address regulatory lag. According to the Company, it will invest $444 million and approximately $500 million in energy (electricity and natural gas) delivery infrastructure during 2006 and 2007 respectively. PSE contends that while customers will benefit from investments in this transmission and distribution plant as soon as the infrastructure is put into service, the Company will not recover the depreciation expense it incurs or any return on its invested capital until the conclusion of its next general rate case following the plant's in-service date.

37 PSE undoubtedly recognizes regulatory lag is typical of rate base, rate of return ratemaking grounded in an historic test year adjusted for changes that are known and measurable at the end of that test year.[24] Indeed, the circumstances of which PSE complains are simply an inherent part of the historic test period approach, which requires the application of certain fundamental ratemaking principles that we and many other regulators endeavor to apply consistently over time. In particular, we disfavor and typically avoid single-issue ratemaking and we are careful to preserve so far as is reasonable the "matching principle" that relies on our consideration of all revenues, costs, and adjustments in the context of a test year with a definite ending date. Thus, PSE asks us to approve a novel mechanism that departs from fundamental principles of ratemaking.

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[23] The mechanism would not apply to depreciation on generation investments, which can be addressed in a PCORC.

[24] Regulatory lag has both positive and negative attributes. On the positive side, for example, it is widely recognized that regulatory lag introduces beneficial discipline to management decisions and the company may reap the benefit of cost reductions between rate cases. On the negative side, there can be a significant gap in time between when useful plant is placed in service and when recovery in rate base is allowed on such investment.

38 PSE argues the Commission has in prior orders recognized it is appropriate to address earnings attrition when there is growing mismatch between revenues, expenses and rate base. According to the Company, it faces such circumstances due to regulatory lag and therefore its depreciation tracker or "known and measurable" rate base adjustment proposals are appropriate.[25] PSE states it has performed detailed attrition studies that demonstrate earnings attrition, thus justifying the requested relief.[26]

39 It requires extraordinary circumstances to support a departure from fundamental ratemaking principles. In prior cases the Commission has required "a clear and convincing showing that the Company will be denied any reasonable opportunity to earn its authorized rate of return without extraordinary relief."[27] We have considered the evidence PSE presented concerning attrition in some detail. Our analysis of the evidence leaves us unpersuaded that PSE will suffer earnings attrition as a result of not recovering depreciation on infrastructure investments it makes between rate cases.

40 Significantly, PSE's attrition study assumes that the Commission will approve the Company's proposed capital structure and rate of return on equity and does not assess other plausible scenarios. These assumptions are unfounded, as we discuss later in this order. Thus, the evidence PSE offers does not convince us that the Company's capital investment between rate cases will erode its earnings at all, much less to the point that it will be denied a reasonable opportunity to earn its authorized rate of return.

41 PSE has not demonstrated financial circumstances that might justify the extraordinary relief represented by the proposed tracker mechanism. Nor has the Company demonstrated that regulatory lag will prevent it from making investments necessary to maintain reliable service to its electric and gas customers.

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[25] PSE Brief ¶45-46.
[26] PSE Reply Brief ¶24.
[27] Staff Initial Brief ¶36 (citing *WUTC v. Washington Natural Gas Co.*, 4th Supp. Order at 29-30, Docket No. UG-920840 (September 27, 1993)); Reply Brief ¶38, fn. 61. *See also* Exhibit 526 (Russell). The Commission has granted extraordinary relief to utilities upon demonstration through attrition studies that circumstances are likely to prevent them from earning their allowed rate of return. Staff is correct to argue that such relief should be granted only under extraordinary circumstances and with clear evidence that the utility would be harmed without such relief.

42 In short, the record simply does not support and we cannot approve a novel mechanism to change rates that will shift risks and costs to ratepayers without the benefit of a full review of revenue and expenses.[28]

3. Post-Test-Period Adjustments to Rate Base

43 Although PSE advocates on brief for its proposed depreciation tracker, discussed above, the Company also states that a rate base adjustment for post-test period investments put into service through June 30, 2006, would be an acceptable alternative to the tracker mechanism.[29] Indeed, several parties state this would be acceptable to them and propose various alternatives.[30] Each of these alternatives is different and would have significantly different rate impacts. They are styled as pro forma adjustments to test-year depreciation expense or rate base, or both, to account for non-revenue producing electric and natural gas distribution or transmission projects completed and put into service after the close of the test-year. We refer collectively to these adjustments as "out-of-period adjustments."

44 PSE initially proposed to include adjustments to reflect the costs of more than 6,000 projects completed and put in service between October 2005 and June 2006. Staff and others objected that this list, including more than 20,000 line entries, could neither be audited nor verified in the time available, if at all. Staff proposed in its brief that it would be reasonable for the Commission to approve, as out-of-period adjustments to rate base, three gas projects and two electric projects. Staff's criteri*a* were that these projects were required either to fulfill reliability standards, such as the Western Electricity Coordinating Council (WECC) reliability criteria or to meet the terms of prior Commission orders. The total additions to rate base for these projects would be $15.3 million for electric rate base and $10.6 million for natural gas rate base.

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[28] The Commission has approved for PSE a PGA, a PCA, the PCORC process, storm cost deferral, and demand-side management tariff-riders. Under these various mechanisms, and via regular general rate proceedings, we have authorized increases in the Company's rates a number of times since 2002, often in expedited proceedings, keeping the Company's revenues abreast of its demonstrable needs.

[29] PSE Initial Brief ¶43; PSE Reply Brief ¶25.

[30] Specifically, Federal Executive Agencies (FEA) in its response case, PSE in its rebuttal case and reply brief and Staff in its brief, propose alternatives to the tracking mechanism.

45 FEA proposed an alternative adjustment to rate base that would allow PSE recovery "of" but not recovery "on" the Company's transmission and distribution projects put in service through June 30, 2006.[31] FEA does not calculate the amount of its recommended addition to rate base.

46 On reply, PSE contends the Staff's proposal to allow a one-time rate base adjustment for a limited number of projects concedes the point that the Commission should approve some out-of-period adjustments. PSE argues, using the Staff criterion, that three additional electricity transmission and distribution projects should be included: Novelty Hill ($23 million), Foss-Bangor ($7.9 million) and March Point ($4.8 million). This would increase the total out-of-period adjustments to electric rate base to $51.2 million.

47 Public Counsel argues against any out-of-period adjustment, predicting that if "piecemeal" adjustments are made to rate base in this case other utilities will "jump on the bandwagon."[32] We share this concern, as a general proposition, and are equally concerned about its implications for our regulatory oversight.[33]

48 We are more concerned in this case, however, that there is very little evidence concerning the specific plant additions individual parties propose we allow as out-of-period adjustments to rate base or for determining allowed depreciation.[34] FEA, through its witness Ralph C. Smith, is the only party that addressed this issue in its case in chief. Mr. Smith's testimony, however, does not identify any specific plant additions.[35] Ms. McLain and Mr. Story testified on rebuttal, but offered little more detail than provided by Mr. Smith. Mr. Russell testified briefly on surrebuttal, and Ms. McLain and Mr. Story with similar brevity on sur-surrebuttal.

49 While these witnesses mention a few major projects by name, they provide far less information than we typically require when evaluating whether to allow additions

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[31] FEA Initial Brief ¶¶48-54. {pp. 22-24}; FEA Reply Brief.
[32] Public Counsel Reply Brief ¶28.
[33] Among other concerns, by allowing inter-period adjustments to rate base we reduce the companies' incentives to file general rate proceedings with reasonable regularity.
[34] PSE's and Staff's proposals would allow for recovery of (*i.e.*, depreciation) and recovery on (*i.e.*, return) the out-of-period additions to rate base. FEA would only allow PSE to recover in rates the associated depreciation expense.
[35] Exhibit 492 at 14:7-19:4.

to rate base even for plant placed in service during the test year. We have scant basis upon which to determine the prudence of these post-test period investments or to determine whether and to what extent they may be used and useful. These determinations should not rest on speculation.

50 In sum, the various proposals for out-of-period adjustments come too late in this proceeding and are supported by too little evidence. Nor have the requirements of due process been fully met. Given that, we could not approve these out-of-period adjustments even were we otherwise so inclined.

51 Although we find this record insufficient to support out–of-period adjustments, there is nothing that precludes PSE from seeking additions to rate base between rate cases so long as the amounts are not so large as to trigger a general rate proceeding under our rules. If the investments are shown to be prudent, the amounts are reasonable, and the plant is demonstrated to be used and useful, the Commission may exercise its discretion to allow recovery in rates. Important considerations guiding that discretion would be whether there has been a very recent general rate proceeding or the Company commits to making a general rate filing soon after the additions are allowed.[36]

52 In this proceeding, for the reasons stated above, we will not authorize any out-of-period adjustments to rate base.

B. Risk Mitigation Proposals—Gas

1. Decoupling

53 Decoupling is a ratemaking and regulatory tool that breaks the link between a utility's recovery of fixed cost**s** and a customer's energy consumption. From a utility perspective, it is a means to ensure recovery of a significant part, or even all of its fixed costs regardless of reduced consumption. One potential source of reduced consumption, at least on a per customer basis, is conservation undertaken by individual customers. Consumption may also be lower at times for other reasons including more energy efficient building codes and appliances, improved insulation, warmer than normal weather, and, of course, price elasticity.

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[36] See supra ¶¶24-27 (discussion re paragraph 10 of the PCA).

54 Conservation advocates and others recognize decoupling as a potentially important tool to promote conservation. This is the primary rationale Staff and NWEC rely upon for decoupling. We acknowledge that improved energy savings from cost-effective conservation, which we strongly support, is a highly appealing rationale for decoupling on its face. We emphasize, however, that decoupling is a merely one regulatory tool in a larger toolbox of devices we might use to promote greater conservation. Indeed, as discussed separately below, we consider and approve in this proceeding an alternative means to promote conservation of electricity through the use of direct incentives and disincentives to the Company—rewards for reaching, and penalties for failure to reach conservation targets. As we also discuss later in this section, this alternative might offer similar promise in terms of promoting conservation of natural gas.

55 As the parties argue, decoupling is principally useful in circumstances where there is a need to promote a more positive company attitude toward conservation by removing what may be a disincentive, or barrier to aggressive pursuit of conservation**;** as consumption declines so may a company's recovery of that portion of its fixed costs embedded in volumetric rates. As we noted in the conclusion of our recent rulemaking, the question of whether decoupling is appropriate and necessary can only be answered in the context of a particular company's circumstances. Our statutory responsibility to regulate in the public interest requires us to look beyond the abstract and examine the evidence to determine whether the facts support this rationale in PSE's case.[37]

56 PSE proposes a decoupling mechanism that it calls the Gas Revenue Normalization Adjustment (GRNA)**,**which is intended to ensure that PSE receives the authorized per customer "margin revenue" regardless of variations of sales volumes due to weather, conservation, or other causes.[38] For each affected service schedule, PSE would determine the annual contribution towards margin and then a

[37] The Commission learned in a 2005 rulemaking proceeding that it is not desirable to take a blanket approach to decoupling. "The Commission believes that the wide variety of alternative approaches to decoupling make it more efficient to address these issues in the context of specific utility proposals included in general rate case filings rather than through a generic rulemaking." Rulemaking to Review Natural Gas Decoupling, Docket No. UG-050369, Notice of Withdrawal of Rulemaking (October 17, 2005).

[38] The term "margin revenue" refers to the revenue necessary for a utility to recover its total cost of service net of purchased gas expenses and other expenses treated as "flow-through" items in rates (*e.g.*, revenue taxes, conservation program riders). A utility's per customer margin revenue is simply its total cost of service, as determined in the most recent general rate case, divided by the number of customers.

monthly margin revenue target.[39] At the close of each month, the Company would defer the difference between the actual margin revenues and the target margin revenues. At the end of the year, PSE would compute a schedule-specific surcharge or credit to recover or refund the deferral balance over the following year.

57 PSE's proposed GRNA would account for all sources of lost margin including, for example, warmer than normal weather, utility-sponsored conservation, and improved building and appliance efficiency standards. According to PSE, the GRNA would prevent the over- or under-collection of margin due to the effects of conservation and weather. In fact, PSE identifies weather normalization as a "critical component" of its decoupling proposal and states:

> The GRNA is designed to help stabilize the level of gas margin revenues that are recoverable from customers on an annual basis. It will periodically adjust the Company's distribution service rates to recover the margin revenues per customer, as established in this general rate case, that fluctuate due to variances in gas volumes caused primarily by weather, energy efficiency gains and conservation efforts.[40]

58 Although supporting decoupling in principle, Staff recommends we reject PSE's proposal in favor of a three-year pilot decoupling mechanism that would allow the Commission to examine its effects on promoting energy conservation. Staff's proposal, however, would only address non-weather related variation in sales volumes and would include only certain residential, commercial and industrial schedules.[41] Staff also proposes a new-customer adjustment to take into account that new customers have lower than average usage.[42]

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[39] PSE proposes to apply its decoupling mechanism to five service schedules:

- Residential General Service Schedule 23
- Commercial and Industrial General Service Schedule 31
- Special Commercial Heating Service Schedule 36
- Special Multiple Unit Housing Service Schedule 51
- Propane Service Schedule 53

[40] PSE Initial Brief ¶89.

[41] I.e., Schedules 23, 31 and 36. Exhibit 561 (Steward) at 8-20.

[42] *Id*.

59 NWEC also supports decoupling as a three-year pilot but would apply it only to the residential class. NWEC proposes that annual rate adjustments be limited to three percent and that recovery of approved margin be tied to achievement of certain energy efficiency targets. On rebuttal, PSE opposes both the proposed annual rate limit and the performance measure.

60 Public Counsel opposes any decoupling program.[43] Public Counsel argues that the principal effect of PSE's decoupling proposal, like the Staff and NWEC alternatives, is simply to guarantee PSE's revenue and, perhaps, to generate what Public Counsel terms windfalls for the Company.

61 For all of its ostensible advantages, decoupling also has disadvantages**,** notably the shifting of risk to ratepayers, including the risk of fluctuations in weather under the Company's proposal. Under PSE's proposal, at the end of a warmer than average year, customers on the system for the following year will be required to pay surcharges to ensure that PSE recovers all of its fixed costs from the prior period. All customers will experience these surcharge rates regardless of lower use by individual customers and lower use overall. Granted, some customers will benefit in a colder than normal year when the Company over-recovers its fixed costs and credits continuing customers' bills in the following year.[44] This, however, points us to a second potentially serious problem***;*** the distortion of price signals and consequent dampening of customer conservation initiatives.

62 Balancing fixed cost recovery on an annual basis via a surcharge or credit mechanism diminishes the value of rates as a means to send appropriate price signals to customers. Based on changing energy market conditions, price signals undoubtedly affect individual customer choices to conserve or not. This price signal may be weakened if customers conserve and then are faced with paying a surcharge that reduces their financial benefit. Just as we must be concerned that in some instances the absence of decoupling or something similar may prove a disincentive to a company promoting conservation, the presence of decoupling, and associated surcharges, may prove a disincentive to customers who might be inclined to conserve if it is to their financial advantage.

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[43] Exhibit 506 (Brosch), at 3, 18-21.

[44] We note in this connection the disadvantage of a surcharge mechanism resulting in a degree of mismatch between customers whose usage patterns contribute to over- or under-recovery and customers who receive a credit or must pay a surcharge.

63 A third potential problem, vigorously argued by Public Counsel, is the risk over time of distorting the "matching principle."[45] Costs and revenues are carefully balanced or "matched" in a general rate case. If a company is largely assured recovery of fixed costs and most variable costs are routinely passed through to customers (*e.g.*, via purchased gas adjustment mechanisms and the like), then there is less reason for the company to file a general rate case. In this context, any cost savings achieved by the company are not shared with customers. The result risks over-earning by the company and over-paying by the customers.

64 Considering this, and bearing in mind the burden of proof lies with the Company we must examine carefully whether the record in this proceeding is sufficient to prove the potential advantages from decoupling outweigh its potential disadvantages in PSE's case.

65 PSE has an outstanding record in terms of encouraging conservation and achieving significant amounts of conservation on its system over time. Indeed, as PSE observes in its Initial Brief: "It is uncontested that PSE is making great efforts at energy efficiency, both electric and gas."[46] While we commend the Company's efforts and success in this regard, and recognize the apparent irony in its effect on our analysis, it is nevertheless true that if there is little or nothing to be gained from implementing a decoupling mechanism in terms of increased Company conservation efforts, then there is no conservation rationale to approve a program. Decoupling is a means to an end, not an end in itself. It is neither an entitlement nor a reward. Considering this, we reject suggestions in several parties' briefs that if we do not authorize decoupling in this proceeding we are somehow penalizing PSE for its longstanding commitment to conservation.

66 Some parties argue that decoupling is an important tool in shaping corporate culture so that utilities will aggressively implement, or at least be open to pursuing conservation measures. This makes sense in the abstract, and may prove to be true in the case of individual companies. Decoupling, however, is not necessary to infuse PSE's corporate culture with such an attitude. PSE's corporate culture insofar as conservation is concerned is strongly favorable, and has been for many

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[45] Public Counsel Initial Brief at ¶¶45-47
[46] PSE Initial Brief at ¶92 (citing Harris, Tr. 115:13 – 116:22, 120:8 – 122:7; Amen, Tr. 499:15-24, 530:11-20; Exhibit 561 (Steward) at 10:10-18).

years. As Ms. Harris testified: "Our conservation programs span decades; we have been a leader in conservation for decades."[47]

67 Mr. Shirley testified that the Company has an active conservation program on the gas side that developed without decoupling.[48] Significantly, it appears from Mr. Shirley's testimony that the Company has exploited, for the time being at least, most or all of the cost-effective gas conservation programs available.[49] Nevertheless, the Company continues to pursue every possibility for cost-effective gas conservation measures. PSE's performance in this regard is confirmed by Staff.[50] While decoupling might in theory remove any disincentive that arguably is a barrier to PSE investing in more gas energy efficiency measures, if there are not additional cost-effective measures in which to invest, no conservation benefit is gained by implementing decoupling.[51]

68 In addition to the fact that the decoupling proposals advanced in this proceeding apparently will have little to no effect on the amount of conservation pursued by PSE, we find other reasons to reject the proposals. One reason is that without an earnings cap or some other mechanism to preserve some degree of risk for the Company, this type of mechanism, along with the PGA, makes it even less likely that PSE will file general rate cases. As previously noted, the risk of over-earning is a concern assuaged by periodic rate cases and consequent Commission oversight. Further, without performance measures, neither the Commission nor the public can evaluate whether or to what extent decoupling is actually promoting incremental amounts of conservation. Yet, PSE opposes any sort of earnings cap or performance measure.

69 Finally, our consideration and approval of an electric conservation incentive mechanism in this proceeding persuades us that such approaches may more effectively target the goal of increasing PSE's conservation efforts than does decoupling. Incentive programs are simple to implement, easy to understand, very direct in their operation and easier to evaluate. Though there is no basis to establish such a program in this proceeding given the Company's decision to

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[47] Shirley, Tr. 115:20-22.
[48] Shirley, Tr. 585:6-10.
[49] Shirley, Tr. 618:20-623:3.
[50] Steward, Tr. 765:19-23; 767:9-768:5.
[51] Neither the Company, nor Staff proposes that specific conservation goals be implemented in connection with decoupling. In fact, PSE actively opposes the idea of such goals.

pursue decoupling on the gas side to the exclusion of an incentive program, this may be an approach the Company could explore in a future filing.

C. Capital Structure and Cost of Capital

70 PSE's currently authorized rate of return (ROR) is 8.40 percent with a return on equity (ROE) of 10.3 percent and an equity ratio of 43 percent. The Commission set these factors on February 18, 2005, in Order No. 6, in Docket Nos. UG-040640 and UE-040641 (consolidated). In this docket, filed just 12 months later, the Company requested an overall rate of return of 8.76 percent based on a return on equity of 11.25 percent and an equity component of 45 percent.[52]

71 Table 5 summarizes PSE's currently approved capital structure and cost rates and the recommendations of the Company, Staff and ICNU on brief. Our determinations, discussed in detail below, are shown in Table 6.

TABLE 5
Capital Structure and Cost of Capital Proposals

	Commission Approved in Dockets UE-040641/UG-040640		**Company Proposal**		**Staff Proposal**		**ICNU Proposal**	
	Share/Cost		**Share/Cost**		**Share/Cost**		**Share/Cost**	
Equity	43.00	10.30	45.00	11.25	43.00	9.38	44.13	9.90
Long-Term Debt	47.53	6.88	48.44	6.64	47.88	6.64	49.71	6.64
Short-Term Debt	3.11	4.81	2.11	6.66	4.67	6.66	.90	6.22
Trust Preferred	6.32	8.60	.70	8.54	.70	8.54	5.22	8.54
Preferred Stock	.04	8.51	3.75	7.61	3.75	7.61	.04	7.61
TOTAL ROR	**8.40**		**8.76**		**7.87**		**8.17**	

52 None of the three expert witnesses in this case develops a recommendation by identifying relevant market circumstances that have changed since the Commission's determination in this recent order.

TABLE 6

Commission Determination of Capital Structure and Cost of Capital

	Share %	Cost %	Weighted Cost %
Equity	44.00	10.40	4.58
Long-Term Debt	48.00	6.64	3.19
Short-Term Debt	2.70	6.66	0.18
Trust Preferred	5.25	8.54	0.45
Preferred Stock	0.05	7.61	0.00
TOTAL ROR			**8.40**

1. Capital Structure

72 In its most recent order approving PSE's capital structure the Commission set the equity ratio in the Company's capital structure at the level found "most likely to prevail, on average, over the course of the rate year."[53] Mr. Gaines, for the Company, recommends a capital structure that includes 45 percent equity based on what the Company asserts are the planned levels of capitalization for the rate year: January 2007 through December 2007.[54] Mr. Gaines argues, among other things, that the Company requires a higher share of equity capitalization because it "faces an unprecedented level of capital spending to support new customer additions, replace aging infrastructure and to add new electric generating resources." According to Mr. Gaines, these capital needs cannot be funded by internal cash flows.[55]

73 Mr. Hill, for Staff, recommends a capital structure that holds constant the currently approved 43 percent equity share and modifies the Company's requested structure by replacing approximately $100 million of projected equity capitalization with short-term debt.[56]

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[53] *WUTC v. PSE,* Docket Nos. UG-040640 and UE-040641 (consolidated), Order No. 6 (February 18, 2005) ¶40.
[54] Exhibit 136C at 1.
[55] Exhibit 131CT (Gaines Direct) at 6.
[56] Exhibit 531CT (Hill Direct) at 37.

74 Mr. Gorman, for ICNU, recommends a capital structure equivalent to the Company's 2005 year-end actual capitalization.[57] Mr. Gorman argues that the Company's proposed capital structure is hypothetical and is not based on known and measurable data.

75 Thus, determining capital structure in this case boils down to our resolution of two issues:

1) Should a hypothetical equity share be approved based on the Company's rate year projections?

2) If equity share is based on historical data, what average or point in time should be used?

76 The Commission has approved hypothetical capital structures when there was a clear and compelling reason to do so. The Company is correct when it states that the last two capital structures approved by the Commission were based on projected or anticipated rate year capitalization. However, this was an exercise of judgment considering facts and circumstances shown at the time to be relevant, not a policy determination by the Commission. In these prior cases, the Commission was focused on balancing economy and safety by reducing the Company's leverage and improving the safety in its balance sheet. In this case, the Company's balance sheet has improved substantially from its over-leveraged condition that prevailed during 2000 and 2001.

77 The Company contends that it needs a higher equity share to support its projected high level of capital expenditure. The Company does not contend that its current balance sheet is too weak to attract capital, just that a stronger balance sheet might improve its debt rating and reduce its borrowing costs. Staff makes a detailed case for why the Company's balance sheet and access to capital is sufficient at its current rates, rate of return and capital structure to support the capital program which, according to Staff, actually peaks in 2006.[58]

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[57] Exhibit 471CT (Gorman Direct) at 5.
[58] The Company disagrees, replying that the construction program forecasts included in the 2005 10-K and rating agency presentations do not include new generation assets for 2007 and 2008 and that its Board has not approved the resource acquisition plans for 2007 and beyond, which it expects to be significant. PSE Reply Brief ¶50 fn. 89.

78 It may be that the Company will increase its actual equity ratio with either debt retirements or new issuances of stock during the rate year, but ICNU and Staff are correct to argue that at this point this is only speculation. The record does not demonstrate a compelling reason to approve a capital structure that contains more equity than is actually supporting the Company's operations, and there is no certainty that the Company will actually increase its equity share during the rate year. Consequently, we find an actual rather than hypothetical capital structure should be used in this case.

79 Turning to the historic data, ICNU proposes we use the Company's actual equity share at year-end 2005, which was 44.13 percent.[59] PSE states that an equity share of at least 44 percent was maintained through June 30, 2006. Both of these figures are known, in contrast to the projections on which the Company relies for its 45 percent rate-year average and on which Staff relies to demonstrate a ratio of 40 percent at year-end 2006.

80 Because it is based on a known change from test-year figures and is supported by the actual equity ratio through June 2006, we find a 44 percent equity share reasonable and we will use that equity share in our return calculations. To improve consistency in the pro forma adjustment of the capital structure we also adjust the Company's short-term debt ratio to reflect the mid-point of short-term debt balances carried by the Company between December 31, 2005, and June 30, 2006. The Company's 10-Q shows the mid-point to be close to 2.7 percent.[60] The Company's 10-Q shows no variation in Trust Preferred or Preferred Stock between these periods. We find no adjustment to these components necessary.[61] In light of our other determinations, we find 48 percent is a reasonable share for the Company's long-term debt.

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[59] The test year in this proceeding ended September 30, 2005.

[60] Exhibit 466 at 16 (Valdman).

[61] We note that both the Company and the Staff propose a share of preferred stock that varies significantly from the actual figures in the test-year, year-end 2005, and June 2006. Presumably the Company's figure is based on its 2007 rate-year projection, but it makes no specific argument regarding preferred stock. Staff appears to use the 2007 rate-year projections for preferred and trust-preferred, rather than actual figures for the test-year, December 2005 or June 2006.

a. Cost of Equity

81 We determine that PSE's cost of equity capital should be set at 10.4% for purposes of setting rates in this proceeding. Coupled with our decision to set PSE's equity share at 44%, the Company's computed weighted average cost of equity is 4.58%.

82 The Commission introduced its discussion of cost of equity evidence in PSE's most recent general rate order with this observation:

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

83 Not counting analytic exhibits and hearing transcripts, we have over 400 pages of testimony on the appropriate cost of equity capital for PSE in this proceeding. Several parties devote significant parts of their briefs to this issue. Yet, the parties are not much closer to agreement today than they were two years ago, and their analyses and results exhibit markedly similar ranges to what we considered just over one year ago. The analytic evidence in this proceeding produces a range for cost of equity from 7.38 percent to 12.85 percent with advocated results ranging from 9.37 percent to 11.25 percent.

84 Little of the extensive testimony offered on this subject focuses squarely on what might have changed in the capital markets or at PSE in the last 18 months to justify a change in the ROE set by the Commission in February of 2005. Instead, as usual, most of the testimony focuses on familiar, rather academic disputes regarding methods, theory and assumptions. To be sure, these disputes affect the level of the experts' ROE estimates, but when they are boiled down to substance, we find that a few key assumptions drive the differences among the analytic results and the recommendations of the three parties. These assumptions are matters of judgment tempered by differing professional orientations. We must look beyond the experts' Discounted Cash Flow, Capital Asset Pricing Model and

similar analyses to a broader body of evidence to make our determinations, which are informed by, but not dictated by the experts' modeling results.

85 We do find evidence of some changes in PSE's circumstances that influence our consideration of this issue. PSE's capital program has grown from forecasts of $400 million and $471 million made in 2004 for the years 2006 and 2007, to forecasts of $854 million and $670 million respectively.[62] It appears, however, that the Company has been able to cover these costs through managing its internal cash flows and issuing new equity and debt without overly taxing remaining borrowing capability. The Company's credit rating has not been downgraded and its stock price recently has been relatively stable.

86 Interest rates in the capital markets have increased, though mainly in the short-term part of the yield curve. The record in the 2005 general rate case contained a forecasted 30-year treasury rate of 4.89 percent. The record in this case includes 30-year treasury forecasts of 4.97 to 5.3 percent—an average of 5.14 percent. By this comparison, forecasted long-term risk free interest rates have increased by about 25 basis points.

87 Given that we are not approving various new risk mitigation proposals made in this proceeding that would affect the balance of risks between PSE and its customers, the weight of the evidence falls on leaving the equity return unchanged or only slightly higher. The expert testimony suggests to us a figure in the range between 10.3 percent and 10.5 percent would be proper. We find 10.4 percent well supported by the record and appropriate, considering the end results achieved.

2. Capital Structure and Cost of Capital Summary

88 We summarize our determinations of the issues concerning Capital Structure and Cost of Capital above in Table 6.

89 Our findings and conclusions concerning the appropriate capital structure and component cost rates produce an overall weighted cost of capital of 8.40 percent. The evidence shows this overall rate of return will be sufficient to attract the

[62] Exhibit 801.

capital the Company may need for infrastructure expansion while at the same time producing financial ratios measuring interest coverage and debt leverage solidly within the ranges required for BBB credit ratings by Standard & Poor's and other rating agencies.[63] With this foundation, and considering the PCA mechanism, PCORC, the purchased gas adjustment (PGA) mechanism and other risk mitigation programs the Commission has previously approved, the Company should have every opportunity, with strong management and improvements in efficiency, to further improve its credit rating and strengthen its overall financial health.

D. Revenue Requirements

1. Electric

90 As previously mentioned, only PSE and Staff put on full revenue requirements cases. PSE originally requested increases of $148.8 million, or 9.21 percent for electric service and $51.3 million, or 5.34 percent for gas service.

91 On July 7, 2006, PSE amended its electricity revenue request via supplemental direct testimony to reflect the additional revenue approved in Docket UE-060783, which updated the **C**ompany's base power costs. PSE's amended electricity revenue request was reduced to $42.9 million and its amended natural gas revenue request was reduced to $39.2 million.

92 By the time of its rebuttal case, PSE asserted the need to recover a revenue deficiency of $33,778,533 in electric rates, a 1.9 percent increase.[64] On the gas side, PSE asserted a revenue deficiency of $39,008,416.[65] PSE proposed a 4.06 percent rate increase to recover this amount.

93 Staff contended in its response case that the company should be required to reduce rates to reflect excess revenue of $40,698,572.[66] Staff argued in the response round of testimony that the company's revenue deficiency on the gas side is $19,348,874.[67]

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[63] Exhibit 10.
[64] Exhibit 439 (Story Rebuttal).
[65] Exhibit 232CT (Karzmar Rebuttal) at 2:4-8.
[66] Exhibit 521 (Russell Response).
[67] *Id.*

94 On September 15, 2006, PSE and Staff filed their Agreement on Revenue Requirement Adjustments. PSE and Staff agree to all but 4 issues that potentially impact the electric revenue requirement:

- Rate of Return,
- Power Cost
- Directors & Officers (D&O)insurance
- Depreciation Tracker

95 We discussed previously and resolved the issues related to rate of return and the depreciation tracker proposals. As to proposed adjustments to the electric revenue requirement, then, only two remain in dispute. Our resolution of the D&O insurance adjustment impacts the gas revenue requirement as well.

96 We digress briefly to caution that while we approve the revenue requirement agreement between PSE and Staff, and resolve only the few issues disputed between the parties, we have an independent concern about the recovery of executive compensation. We recognize that the activities of the executive officers of regulated companies such as PSE confer some benefit on the ratepayers, but the officers' fiduciary responsibilities run to the shareholders, not the ratepayers. This is a fact that we must keep in mind in considering what part of executive compensation is appropriate for recovery in rates.

97 Because it was not expressly identified as an issue in this proceeding, we do not have a record sufficient to evaluate whether there should be some adjustment to the amount of executive compensation allowed for recovery in rates. However, we can and do make clear that we wish to see this subject fully developed on the record in any future case that includes proposed increases in this expense.[68] We do not suggest it is within our purview to dictate to the board of directors the level of executive compensation and performance benchmarks it should approve, but in this era of substantially escalating executive compensation we are obligated to consider how much the ratepayers of a regulated monopoly should be required to pay.

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[68] We do not single PSE out in this regard. We will have the same expectation in proceedings involving other companies we regulate.

98 Returning to the adjustments that are expressly contested in this proceeding, we summarize the parties' positions in Table 7 below. Our discussion and decisions follow.

TABLE 7
Contested Restating and Pro Forma Adjustments – Electric and Gas

Adjustment Description	Company Position		Staff Position	
	Revenue requirement	Net operating income	Revenue requirement	Net operating income
Electric				
Power Costs	312,839,936	(194,190,197)	293,563,457	(182,224,643)
Director and Officer Insurance	21,412	(13,291)	(508,371)	315,563
Gas				
Directors and Officers Insurance	14,392	(8,946)	(341,697)	212,399

a. Contested Adjustments

i. Power Costs

99 The Power Cost Baseline Rate is the expected level of power costs around which the Company's power cost adjustment mechanism works. The Company's filing would set annual power costs at $966 million, an approximate $91 million increase from current levels set via a compliance filing in June 2006, as required by the Commission's Order approving the Company's 2005 PCORC.[69]

100 Staff, Public Counsel and ICNU (Joint Parties) recommend a $19.2 million reduction to PSE's revenue requirement for power costs relative to the Company's June 2006 compliance filing. Roughly one-third of the proposed reduction is related to adjustments to AURORA model[70] inputs and two-thirds is related to adjusting the AURORA output to reflect market prices for sales and purchases of

[69] Exhibit 260.
[70] AURORA is the power cost model PSE used to estimate net power costs within the west-wide grid of utilities. The AURORA model includes fuel costs, plant statistics and costs to buy and sell power.

wholesale electricity at the mid-Columbia trading hub. On brief, ICNU speaks for the Joint Parties.[71]

Updated Natural Gas Costs

101 The Joint Parties argue PSE should be required to update its power cost projection to reflect natural gas prices that decreased subsequent to the Company's supplemental filing. The Company's supplemental filing on July 7, 2006, included power costs based on an $8.57/MMBtu average price at Sumas for the rate year. However, as of September 20, 2006 (the time of the hearing), the Joint Parties state the average Sumas gas price for the 2007 rate year was less than $7.00/MMBtu.[72] This is incorrect. As shown on the exhibit the Joint Parties cite, the $7.00 price is a daily price, not an average price. The three-month average price near the end of September 2006 was $8.09, as PSE acknowledges.

102 The Joint Parties contend that the Company should be required to file a gas price update based on an average of 2007 forward market prices from the three-month period September 1, 2006, through November 30, 2006. They point to the Commission's prior statement: "power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings."[73]

103 PSE states that it does not object to updating its power cost projections for the rate year. However, the Company asserts that it would be insufficient to update only natural gas prices. According to the Company, other changes in the 2007 power portfolio that are now known should also be included if power cost projections for the rate year are to be updated.[74]

104 The Commission has stated its preference for updated gas costs in prior cases, relying on much the same methodology and similar data to what is present in our

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[71] Staff relies on ICNU and Public Counsel to present its argument on power costs "…Staff adopts the arguments presented [by Public Counsel and ICNU] in their briefs on those subjects." (Staff Brief ¶6, fn 11) Public Counsel, for its part, "…adopts the ICNU brief on this issue." (Public Counsel Initial Brief ¶130).
[72] ICNU Initial Brief ¶12 (citing Exhibit 289C).
[73] *WUTC v. PSE,* Docket No. UE-040641, Order No. 06 (Feb. 18, 2005) ¶108. ICNU Initial Brief ¶¶11-14.
[74] PSE Initial Brief ¶109.

record here.[75] The method for calculating such costs is now well-established. The update should be a straightforward, mechanical and non-controversial process. We determine that PSE should be required to update gas costs using the three-month average through the end of November 2006 when it reruns AURORA in support of its compliance filing in this proceeding.

105 As to the other costs PSE proposes be updated, costs it does not identify except by reference to brief redirect examination of Company witness David Mills, there simply is no record to support any such update even were we otherwise inclined to authorize it. While there are few if any questions of fact regarding the price of natural gas at the Sumas trading hub, we simply cannot know what disputes may arise over other potential changes in the power portfolio that PSE would propose. Accordingly, while we find it appropriate for PSE to rerun AURORA with updated gas costs, we do not find support in the record for updating other costs.

Hydro Shaping

106 The Joint Parties argue the "shaping factors" PSE used in its AURORA modeling do not produce reasonable generation amounts during the more valuable on-peak periods.[76] The Joint Parties point to PSE's April 14, 2006, position and exposure report and assert it shows that PSE expects to achieve higher levels of peak period hydro generation than it has assumed in its AURORA modeling. The Joint Parties further assert that PSE's AURORA hydro-shape conflicts with the hydro shaping factors used in the BPA's 2006 Risk Analysis Study Documentation. The shaping factors recommended by the Joint Parties would reduce PSE's power costs by $6.0 million.[77]

107 PSE says its position and exposure report provides the Company with a "stretch goal" to maximize the value of hydro resources for operational purposes, but does not capture certain dynamic variables that impair the Company's ability to actually optimize this resource.[78] Mr. Mills, in fact, identified several factors that limit the

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[75] ICNU Reply Brief ¶7. *See WUTC v. PSE*, Docket No. UE-050870, Order No. 04, ¶16 (Oct. 20, 2005).
[76] The "shape" of hydro generation between on-peak and off-peak periods is an input to the AURORA model.
[77] ICNU Initial Brief ¶¶28-30, ICNU Reply Brief ¶¶12-13.
[78] Exhibit 269C (Mills) at 24:11-16.

Company's ability to optimize hydropower generation between on-peak and off-peak hours.[79] These factors include:

- Environmental restrictions (fish protection).
- Reservoir restrictions (flood control).
- Loading factors (system coordination).
- Unit outages.
- Operating reserves.
- Wind integration.

PSE further states that over the last five years it has been able to shape only 62.1% of its hydro generation into peak periods, an amount lower even than the AURORA rate year projections of 64.5%.[80]

108 The operational constraints on PSE's ability to operate its hydro resources in a theoretically optimum way are real and must be taken into account in determining power costs. It does not appear that the Company's position and exposure report or BPA's Risk Analysis Study takes account of these limiting factors on PSE's ability to generate additional hydro during peak periods. PSE did take these factors into account in its AURORA modeling. We find PSE's hydro shaping is reasonable for purposes of running AURORA, including the rerun for natural gas costs we require to support the Company's compliance filing in this proceeding.

Minimum Up and Down Times for Gas-Fired Combustion Turbines

109 The AURORA model's developer, EPIS, Inc., furnishes much of the input data PSE and other utilities rely on when running the model. These data include the operating characteristics of generating resources in the western United States. The Joint Parties assert that PSE made no effort to verify the accuracy of operating parameters for generating resources not owned by the Company and that the supplied data included overly restrictive minimum up- and down-times for large combined cycle combustion turbines (CCCTs).[81] The Joint Parties would replace

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[79] *Id.* at 25:6-26:28.

[80] PSE Initial Brief ¶115.

[81] The minimum up-time for a resource is the minimum number of hours that a resource must operate continuously, and the minimum down-time is the minimum number of hours that a facility must remain shut down before starting up again.

the EPIS-supplied up- and down-times (*i.e.*, 16 hours on and 8 hours off) with what they allege are "more realistic values of a minimum up time of 6 hours and a minimum down time of 4 hours."[82] The Joint Parties calculate that using these modified run times would lower PSE's costs by $2.4 million.[83]

110 PSE agrees that most CCCTs are physically capable of operating as the Joint parties recommend, but Mr. Mills' testified that several factors preclude CCCTs from being operated in this way:

- Increased maintenance costs.
- Air quality and other permits.
- Operating contracts.
- Physical characteristics of some plants.[84]

It is highly unlikely that any individual utility has the wherewithal or access to necessary data to develop operational parameters for each regional generating resource. Nor has ICNU obtained and relied on such data. It is reasonable for the Company to rely on the vendor of the AURORA model to supply this type of data. We find PSE's use of EPIS-supplied run times reasonable.

<u>Forward Market Electric Prices</u>

111 The Joint Parties argue forward electric market prices should be substituted for those generated internally by AURORA when determining PSE's power costs. The Joint Parties describe AURORA-derived electricity prices as based on "hypothetical inputs for supply and demand that do not accurately reflect real-world conditions."[85] The Joint Parties assert the benefits of using a three-month average of forward market prices include:

- Providing an unbiased estimate of future electricity prices.
- Reflecting PSE's purchasing strategy with greater accuracy.
- Establishing a uniform approach to estimating both electric and natural gas prices to ensure forecasts are not mismatched.

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[82] ICNU Initial Brief ¶24.
[83] *Id.* ¶27.
[84] Exhibit 269C (Mills) 18:15-19:22.
[85] ICNU Initial Brief ¶39.

- Eliminating the inefficiency of constantly updating the AURORA data set.[86]

112 The Joint Parties contend their recommendation is consistent with Commission precedent and with arguments PSE has made in favor of using forward natural gas prices instead of a fundamentals model for determining gas costs.[87]

113 The Commission has relied on, audited, and approved the AURORA model in many proceedings. The Joint Parties provided no analytical support to show that a three-month average Mid-C market forecast predicts actual electricity prices or provides more rigorous results than does the AURORA model.[88] In addition, while gas costs are an input to the AURORA model, electricity prices are an output. Adjusting the model's results after-the-fact may be fundamentally inconsistent with the model's core logic. On the present record, we simply do not know.

114 We do not close the door on the possibility that forward market electric prices might be useful in determining power costs, but additional analysis is required before we could take such a step. As a threshold matter, an analysis is needed to support the statistical validity of using an average of three-months of Mid-C market prices to project power costs. The Company has expressed a willingness to "investigate this idea further."[89] We accept this offer and expect to hear more about this subject in PSE's next general rate proceeding, if not before.

Determining Extreme Peak Loads

115 The Joint Parties argue PSE should be required in future rate filings to calculate the peak requirements temperature based on a historical record of at least thirty years. The Joint Parties assert this approach would ensure the use of a more probable temperature on which to base peaking costs. The Joint Parties contend the Company's current method has a higher probability of including unrealized peaking costs in base rates. The Joint Parties' only recommendation in this

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[86] *Id.* ¶42.
[87] *Id.* ¶14.
[88] We note the Commission relied on thorough and detailed statistical analyses when considering whether it should rely on forward gas prices to estimate the fuel costs for gas-fired generation.
[89] Exhibit 269C (Mills) at 30:10-11.

connection is to adopt this methodology in future rate filings. They do not propose an adjustment to PSE's revenue requirement in this proceeding.

116 PSE does not agree that peak temperature should be based on the historical temperature experienced over the same time period used for weather normalization. Nonetheless, the Company says it is open to collaborating with others to examine the appropriate historical period to use when determining design peak temperature.[90] We encourage such study and support the parties' efforts to improve upon current methods for determining factors that are important to power cost modeling in proceedings such as this one.

ii. Director and Officer Insurance

117 The Company allocated the costs of Puget Energy's director and officer ("D&O") insurance premiums among PSE and its subsidiaries using the method approved in Dockets UE-920433, UE-920499 and UE-921262. Staff's argument that PSE failed to establish a reasonable basis for continuing to use the allocation method the Commission approved in 1992 is not persuasive given that Staff offers no analysis to show why the method should be abandoned. Staff developed this methodology in the first place and it has been used for more than a decade, apparently without challenge until now.

118 PSE, contrary to what Staff argues, allocated a portion of the test year insurance premiums to Infrastrux, which was sold on May 7, 2006, during the test year.[91] The Company states that Puget Energy's D&O insurance liability did not change as a result of the sale of Infrastrux.[92]

119 Staff's approach and argument suffers from two other significant deficiencies. Staff's proposed adjustment allocates D&O premiums to Infrastrux, yet does not allocate any D&O premiums to non-utility subsidiaries, Puget Western Inc., and Hydro Energy Development Corp., both of which PSE continues to own. Staff does not explain this inconsistency.

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[90] Exhibit 269C (Mills) at 33:18-35:6; PSE Reply Brief ¶122.
[91] PSE Initial Brief ¶125 (citing Exhibit 232C (Karzmar) at 12:18-19.).
[92] *See* Exhibit 232C (Karzmar) at 13:19-21.

120 Staff's methodology also relies in part on the respective number of employees at PSE and Infrastrux, yet shows no relationship between the number of employees, the risks against which D&O insurance provides financial protection, and D&O insurance premiums. D&O insurance is largely intended to protect directors and officers from shareholder or other suits alleging negligence. We cannot infer, absent any evidence or analysis by Staff, what relationship the number of employees in the respective companies might have to the risk of negligence by a director or officer and, hence, to the allocation of premiums.

121 We find PSE's allocation of D&O insurance premiums reasonable and adopt the adjustments shown in Table 8, line 40 and Table 10, line 27 for electric and gas, respectively.

b. Uncontested Adjustments

122 We have reviewed the uncontested adjustments summarized in Table 8 and find them reasonable. We adopt these adjustments for purposes of setting rates in this proceeding.

TABLE 8
Restating and Pro Forma Adjustments – Electric

Line No.	Adjustment	NOI	Rate Base
1	Temperature Normalization	$7,424,007	
2	Revenues & Expenses	218,656,441	
3	Federal Income Tax	4,185,813	
4	Tax Benefit of Pro Forma Interest	(2,916,387)	
5	Conservation	11,852,001	(28,822)
6	Bad Debts	(1,044,352)	
7	Amortization of Deferred Taxes Regulatory Asset	(1,337,206)	
8	Miscellaneous Non-Operating	627	
9	Oregon Prop. Taxes for 3rd AC	(484,484)	
10	Baker Hydro Relicensing Costs	(385,657)	26,254,348
11	Tree Watch Expense	(639,229)	
12	New York Stock Exchange Fees	-	
13	Depreciation on CWIP In-Service	(56,700)	
14	CWIP In-Service Rate Base		3,317,734
15	Property Taxes	383,183	
16	Hopkins Ridge Wind Plant	(9,389,305)	147,154,987

17	Excise Tax & Filing Fee	(384,314)	
18	Montana Energy Tax	8,557	
19	Interest on Customer Deposits	(227,184)	
20	SFAS 133	592,392	
21	Rate Case Expenses	340,717	
22	Property Sales	(18,149)	
23	Property & Liability Ins	(288,833)	
24	Pension Plan	(2,565,770)	
25	Wage Increase	(2,512,047)	
26	Investment Plan	(99,416)	
27	Employee Insurance	(669,622)	
28	Montana Corporation. License Tax	(167,307)	
29	Storm Damage	(197,617)	
30	Regulatory Assets & Liabilities	(2,887,461)	(54,943,645)
31	Wild Horse Plant	(19,715,599)	356,220,868
32	Incentive Pay	690,180	
33	Gen. Office Relocation	(1,644,955)	(3,139,603)
34	Other Amortization	5,065,947	
35	Demand Response Program	0	
36	Depreciation	-	
37	Production Adjustment	787,513	(11,102,293)
38	Total	$202,355,783	$463,733,574
	Contested adjustments		
39	Power Costs[93]	(194,190,197)	
40	D&O Insurance	(13,291)	
41	Total contested and uncontested adjustments	$ 8,152,295	$ 463,733,574

c. Summary of Electric Revenue Requirement Determination

123 We summarize the results of our electric revenue requirement determinations in Table 9.

[93] Exhibit 440, Power Costs (Adjustment 20.03), line 34. Exhibit 4C, PSE NOI, line 4 shows a slightly different amount for power costs, $194,113,815. The effect of this difference on revenue requirement (Table 9) is slight (*i.e.*, $17,051,190 instead of $17,174,242) and the power cost adjustment will change, in any event, when PSE reruns AURORA as required in this Order.

TABLE 9

Electric Revenue Requirement
Docket No. UE-060266

Rate Base Rate of Return	$ 2,977,316,193 0.084
NOI Revenue Requirement Adjusted NOI	250,094,560 $ 239,433,935
Difference Conversion Factor	10,660,625 0.6207334
Gross Revenue Requirement Increase (Decrease)	17,174,242

2. Gas

a. Contested Adjustment

i. Director and Officer Insurance

124 This issue is the same as in the case of the electric revenue requirement and our reasons for accepting PSE's allocation of D&O premiums are the same for the gas revenue requirement. The allowed adjustment is shown above in Table 7.

b. Uncontested Adjustments

125 We have reviewed the uncontested adjustments summarized in Table 10 and find them reasonable. We adopt these adjustments for purposes of setting natural gas rates in this proceeding.

TABLE 10

Restating and Pro Forma Adjustments -- Gas

Line No.	Adjustment	NOI	Rate Base
1	Revenue & Expenses, Temperature Normalization	$13,696,529	
2	Federal Income Tax	490,787	
3	Tax Benefit of Pro Forma Interest	(6,778,498)	
4	Conservation	2,426,926	
5	Bad Debts	(236,343)	
6	Remove Penalties	348	
7	Amortization of Deferred Taxes Regulatory Asset	(923,574)	
8	Depreciation on CWIP In-Service	(55,461)	
9	Rate Base Adjustment CWIP In-Service		2,857,353
10	Property Taxes	469,425	
11	Excise Tax & Filing Fee	389,325	
12	Rate Case Expenses	(78,781)	-
13	Property & Liability Ins	123,942	-
14	Pension Plan	(1,603,511)	-
15	Wage Increase	(1,460,754)	-
16	Investment Plan	(62,124)	-
17	Employee Insurance	(418,486)	-
18	Incentive Pay	431,333	-
19	Interest On Customer Deposits	(131,750)	
20	Property Sales Deferred Gains/Losses	456,881	
21	General Office Relocation	(914,888)	(1,746,177)
22	Low Income Amortization	1,361,790	
28	Everett Delta Pipeline Expansion	48,303	-
29	Spirit Ridge Adjustment	-	-
26	Total	$7,231,420	$1,111,176
	Contested adjustment		
27	D&O Insurance	(8,946)	
28	Total contested and uncontested adjustment	7,222,474	1,111,176

c. Summary of Gas Revenue Requirement Determination

126 We summarize the results of our gas revenue requirement determinations in Table 11.

TABLE 11
Gas Revenue Requirement

Rate Base	$	1,180,351,743
Rate of Return		0.084
NOI Revenue Requirement		99,149,546
Adjusted NOI	$	79,718,936
Difference		19,430,611
Conversion Factor		0.6216003
Gross Revenue Requirement Increase (Decrease)		31,259,011

E. Electric Rate Spread and Rate Design Settlement

127 PSE, Staff, and other parties that took an active interest in the rate spread and rate design issues submitted a proposed Settlement Agreement on July 25, 2006, which they ask the Commission to approve and adopt to resolve all rate spread and rate design issues. The Settlement Agreement is supported by Joint Testimony addressing why the Agreement will result in rates that are just and reasonable, and consistent with established Commission policies. It is unopposed.

128 The parties agree to use PSE's electric cost-of-service study, rate spread, and rate design. According to the settlement, any revenue requirement increase will be allocated among the various customer classes and rate schedules in proportion to the rate spread proposed by PSE. Most electric rate classes are relatively close to parity (*i.e.*, rates recover 97% to 130% of the costs caused by a given customer class) and the proposed rate spread would bring each rate class even closer to parity without causing rate shock.

129 We determine the electric rate spread and rate design proposals presented in the parties' Settlement Agreement are reasonable and should be approved and adopted. The Settlement Agreement is attached to this order as Appendix A and is incorporated into the body of this order by this reference.

F. Gas Rate Spread and Rate Design.

Rate Spread

130 PSE argues its proposed gas rate spread assigns the costs of providing service to the customers who cause the costs to be incurred, improving parity among customer classes while not causing rate shock. PSE states that its rate spread analysis and results consider:

- The results of the Company's recent cost of service (COS) study.
- Each class's contribution to present revenue levels.
- Customer impacts.
- Appropriate price signals to customers.
- Revenue stability.[94]

Seattle Steam supports PSE's rate spread proposal despite acknowledging that it would slightly increase Seattle Steam's bill. According to Seattle Steam, the Company's proposal is superior because it better comports with sound rate-making principles than the alternative proposal advanced jointly by Staff, Public Counsel and NWIGU (Joint Parties) and is otherwise more equitable.[95]

131 Staff argues on behalf of the Joint Parties that their proposal represents a fair, balanced application of both PSE's COS study and the most recent "Commission Basis" COS study, which was approved in a general rate proceeding concluded in the mid-1990's. The Joint Parties, like PSE, contend their proposed gas rate spread minimizes severe customer impacts, but moves all classes toward parity. The Joint Parties emphasize that they consider the results of both cost-of-service studies presented in this case. Thus, the Joint Parties argue, their proposal

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[94] Exhibit 38 at 25-27.
[95] Seattle Steam Initial Brief ¶2.

represents "a fair and balanced compromise [among themselves] that results in just and reasonable rates, while avoiding contentious litigation of how a proper cost-of-service study should be conducted."

132 The real point of contention between the parties, as the quote above suggests, is that PSE used a method in performing its COS study to which the other parties object. The Joint Parties object principally because what PSE did is different than what the Commission has approved in the past. Specifically, PSE used system design day as the peak cost allocator in its COS study while the so-called Commission Basis approach uses a five-day historic peak allocator. Staff, arguing for the Joint Parties on reply, quotes extensively from the Commission's 1995 order in which the Commission rejected Avista's proposal to use design day as a basis for calculating peak usage in favor of "actual use by all classes on real peak days" (*i.e.*, historic peak). Staff argues simply that PSE has not provided evidence to show "why the Commission should diverge from this precedent."

133 The record in this proceeding is not adequate for purposes of evaluating PSE's use of the design day as a peak allocator in its COS study. We express no opinion on the subject.

134 That point of contention aside, we must decide between two rate spread proposals considering the results of the individual COS studies, customer impacts, appropriate price signals, and other factors. Using either COS study, the same rate classes are consistently over-parity or under-parity, with the exception of Schedule 87 and Contracts. The primary difference between the two results is the degree to which the interruptible Schedules 85 and 86 and transportation Schedule 57 are above parity. The Joint Parties' rate spread allocates more costs and a fixed dollar amount to these schedules based on nothing more than a compromise of the different rate spread proposals discussed by the Joint Parties.[96] However, there is no rationale developed in the record for assigning a fixed dollar amount, as opposed to a percentage rate increase, to these classes.

135 While the evidence and argument on this issue is not developed particularly well by either party, the Company's case is, on balance, the stronger and more

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[96] Exhibit 581 at 6.

principled approach. We find it reasonable for purposes of determining rates in this proceeding.

Rate Design

136 PSE initially proposed to change its current gas rate design to recover modestly more of its fixed costs through customer charges rather than in its volumetric rates. PSE's as-filed rates, for example, proposed to increase the current residential customer charge of $6.25 to $8.25. Thus, PSE would recover approximately 24 percent of the fixed costs allocated to the residential class in a demand-type charge.[97] Later in the proceeding, PSE modified its proposal to allocate approximately 60 percent of its fixed costs to non-volumetric rates resulting in an increase to $17.00 per month in the customer charge for the residential class.[98]

137 PSE argues the current practice of recovering the majority of its fixed costs in volumetric rates fails to recognize the importance of reflecting in rates the nature of fixed costs incurred to provide utility service. In addition, including fixed costs in volumetric rates results in customers under- or over-paying these costs depending on usage patterns, weather, and conservation efforts. According to PSE, recovering more fixed costs in non-volumetric rates will benefit the Company by ensuring recovery of fixed costs despite variations in usage and will benefit customers because there will be greater stability in their monthly bills.

138 We find PSE's proposed increase of the Residential Schedule 23 customer charge to $17.00 represents too much and too rapid change from a customer perspective. However, we agree with PSE that a reasonable balance must be struck in terms of the company's recovery of its fixed costs via fixed rather than volumetric charges. The Joint Parties' do not disagree with this principle, but argue a gradual move in the direction of recovering more fixed costs via non-volumetric rates is the better approach and maintains consistency with general principles concerning rate shock.[99] This is unquestionably another factor in the balance we must determine.

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[97] PSE Initial Brief ¶136.
[98] *Id.* (citing Exhibit 186 (Hoff) at 186 7:3-8
[99] "Rate shock" in the usual connotation is a concern over sharply increasing bills. However, we use the term here, as do the parties in this case, to refer to a dramatic change in a rate component that may or may not result in individual customers having higher bills overall. In general, because utility rates and billing practices are poorly understood, customers may be expected to be upset with a significant change in either the total bill or a bill component that is separately identified on the billing statement.

139 We find PSE's original proposal, an increase in the customer charge for this Schedule to $8.25 strikes the right balance. This will result in the Company recovering about one-fourth of its fixed costs allocated to residential customers via a fixed charge on each customer's bill. This is about eight to ten percent of an average customer's total bill, considering both fixed and variable costs. This seems to us the right balance point for the recovery of fixed costs via the customer charge.

140 We reject PSE's proposal to increase the Commercial and Industrial Schedule 31 and 41 customer charges thirty-three percent for the same reason as discussed in connection with the residential rate schedule. Moreover, as the Joint Parties argue, if PSE's motivation for the rate changes in Schedules 31 and 41[100] is to encourage customers to take service under a more appropriate rate schedule, PSE should simply notify those customers rather than by sending an indirect message via a change in rate design. We adopt the Joint Parties' rate design for Schedules 31 and 41, including an increase in the Schedule 31 customer charge to $17.50, from the current $15.00, and an increase in the Schedule 41 customer charge to $80.00 from the current $70.00.

141 PSE's proposals regarding Transportation and Interruptible Schedules 57 and 87 are reasonable. We approve PSE proposed increase in the Schedule 57 balancing charge to .000140 cents per therm. We also approve PSE's proposal to maintain the current customer charge for each class, $800 and $500 respectively[101]. We determine that PSE's rate design for these schedules should be adopted.

142 In sum, we approve the rate design proposed by the Joint Parties for all contested rate schedules except Schedules 23, 57 and 87, thus taking a measured step in the direction of allowing PSE to recover more of its fixed costs in non-volumetric rates while avoiding rate shock to any customer class.[102] We accept PSE's

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[100] PSE also proposed to increase the current demand charge from $.50 to $1.00, or 100 percent. Exhibit 38 at 28. We find more reasonable the Joint Parties proposed 40 percent increase in the demand charge to $.70. Exhibit 581 at 11.
[101] The Joint Parties' propose a significant increase to the Interruptible Schedule 87 customer charge.
[102] No one proposes to change the customer charges under Schedules 85 and 86. However, we accept the Joint Parties proposal to increase the volumetric rate for these Schedules. We also approve the Joint Parties recommendation that a procurement charge of 0.65 cents/therm be used for both schedules. Finally, we approve the Joint Parties' proposal to increase the volumetric rate for the first 25,000 therms for Schedule

originally proposed change in the customer charge to Residential Schedule 23. from 6.25 to 8.25. Finally, we approve the uncontested rate design for Commercial and Interruptible Schedules 36, and 51, and Rental Schedules 71, 72, and 74.

143 The Joint Parties propose, and PSE agrees that the Company's current rate schedules should be reviewed before the next general rate case filing to consider how schedules could be combined or separated to better reflect similar types of usage and cost causation. We encourage the parties to undertake such a review prior to PSE's next general rate filing.

G. Low Income Assistance Programs Settlement

144 The parties that proposed settlement of the electric rate spread and rate design issues also resolved among themselves issues concerning PSE's low income assistance programs. The parties included in the electric rate spread and rate design settlement filed on July 25, 2006, and attached to this Order as Appendix A, provisions that address these issues. Their proposal is uncontested, appears reasonable and is supported by the record. We find it will serve the public interest to approve and adopt the settlement to resolve all issues concerning the Company's low income assistance programs.

H. Electric Energy Efficiency Incentive

145 PSE asks the Commission to authorize a performance incentive plan based on the energy savings performance of the Company's electricity conservation programs. The Company's initial proposal was for an incentive based on a percentage of its expenditures under the conservation programs supported by its current conservation tariff rider. Under the as-filed proposal, PSE would earn an incentive payment if its conservation programs achieved conservation savings in any year in excess of a target set by the Conservation Resource Advisory Group (CRAG). The Company's initial proposal was for a five-year program.

146 Staff, Public Counsel and NWEC, in their respective response cases, all supported a conservation performance incentive program in principle, but not the Company's

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85 and, for Schedule 86, the first 1,000 therms. For a comparison of PSE and the Joint Parties' proposals of Schedules 85 and 86, see Exhibit 581at 13.

proposal. Each of these parties proposed a program based on an annual performance target, two-part incentives, penalties for failure to perform, a dead band between the penalty threshold and the incentive threshold and a set of 12 program design and implementation principles. While the three parties agreed on the 12 design principles, they disagreed on the annual target for 2007, the penalty and incentive thresholds, the dead band and the level of incentives and penalties.

147 FEA opposed any incentive program, arguing that ratepayers should only pay prudently incurred costs for conservation and no more. According to FEA, the costs associated with the energy efficiency program should be treated no differently than the costs associated with installation of a supply side option.

148 PSE modified its proposal on rebuttal to fit the basic framework of the programs proposed by Staff, Public Counsel and NWEC. PSE, however, did not agree with all aspects of any of these parties' proposed designs and expressly objected to four of the design principles. PSE argues the Commission should not adopt the following design principals urged by Staff, Public Counsel and NWEC:

- The average measured life for the conservation portfolio should be no less than nine years.
- Measures undertaken by the Northwest Energy Efficiencies Alliance (NEEA) to whom the Company provides fund can only be counted toward the performance target in the year in which funding occurs.
- A new evaluation committee should be formed to verify and evaluate the performance of the Company's conservation measures and programs.
- The program should be a pilot for three years only, with evaluation to occur before the program is continued.

149 Table 12 depicts the 2007 target level, the dead band, and the penalty and incentive thresholds proposed by each party.

TABLE 12

	2007 Target aMW	**Penalty Threshold**	**Incentive Threshold**
PSE	16.5	95 percent	105 percent
Staff	18.3	90 percent	100 percent
Public Counsel	20.0	80 percent	90 percent
NWEC	16.5	95 percent	105 percent

Tables 13 and 14 show the incentive and penalty payment levels proposed by each party. There are two components to the incentive payment:

- Volume of savings at $/MWh of first-year savings.
- Shared Net Savings Incentive – a percentage of the difference between the cost of saved MWhs and the value of saved MWhs ($1.80 per MWh based on an avoided cost of $5.90/MWh – $4.10/MWh average cost of the conservation). This component is included to encourage cost-efficiency in program management and effectiveness.

The tables demonstrate some key differences among the proposals.

- PSE and NWEC do not assess a penalty until performance falls to less than 95% of the target.
- Staff is the only party to calculate incentives and penalties based on the difference between "actual" and the target (except right at the target). The other parties apply penalties and incentives to total MWhs.
- NWEC proposes the largest penalties.
- Public Counsel calculates an incentive before the target is achieved.

TABLE 13

	PSE			**Staff**[103]	
% of Target Ranges	$/MWH	Net (%)	% of Target Ranges	$/MWH	Net (%)
>150%	20	50			
140% - <150%	20	35			
130%- <140%	20	25			
120%- <130%	20	15	140%-< 150%	20	100
115%- <120%	20	10	130%- <140%	20	80
110%- <115%	10	5	120% - <130%	20	40
105%- <110%	4	0	110%- <120%	20	20
100%- <105%	0	0	100%- <110%	20	10
Target = 16.5 aMW			Target = 18.3 aMW	10	5
95% - <100%	0		90%- <100%	0	

[103] Staff's mechanism calculates an incentive for all MWh saved if the target is achieved and incentives for higher levels of performance based on the increment of savings above the target.

90% - <95%	(100)		80%-<90%	(75)	
80% - <90%	(110)		70%-<80%	(80)	
70% - <80%	(110)		60%-<70%	(85)	
60% - <70%	(110)		50%-<60%	(90)	
50% - <60%	(110)		<50%	(95)	
<50%	(110)				

TABLE 14

	Public Counsel			**NWEC[104]**	
% of Target Ranges	$/MWH	Net (%)	% of Target Ranges	$/MWH	Net (%)
			> 150%	20	40
			140%- <150%	20	33
			130%- <140%	20	25
			120%- <130%	20	15
>120%	16	16	115%- <120%	15	5
110%- <120%	16	14	110%- <115%	10	0
105%- <110%	16	12	105%- <110%	5	0
100%- <105%	14	10	100%- <105%	0	0
Target = 20 aMW			Target = 16.5 aMW		
95% - <100%	+12	0	95% - < 100%	0	0
90% - <95%	+10	0	< 95%	(171)	
80% - <90%	0	0		(171)	
70% - <80%	(40)			(171)	
60% - <70%	(60)			(171)	
50% - <50%	(80)			(171)	
<50%	(115)				

150 Staff argues persuasively that it is appropriate to implement an incentive program for conservation on a pilot basis. According to Staff an incentive mechanism reflects sound public policy because:[105]

- The legislative finding in RCW 80.28.024 states, in relevant part, "The legislature finds and declares that the potential for meeting future energy

[104] NWEC proposes a penalty of $1.5 million per aMW of shortfall below 95% of the target. $1.5 million per aMW = $171/mwh.
[105] Staff Initial Brief ¶¶124-131.

needs through conservation measures . . . may not be realized without incentives to public and private utilities. . .”

- The Commission’s policy encourages energy conservation (WAC 480-100-238, the Integrated Resource Plan Rule).
- PSE’s energy conservation expenditures do not earn a return, as owned supply-side resources do, and may result in lost revenues.
- PSE is subject to penalties for failing to achieve conservation targets, but is not rewarded for meeting or achieving those targets.

151 We observe, in addition, that RCW 80.28.260 states in relevant part:

> (3) The commission shall consider and may adopt other policies to protect a company from a reduction of short-term earnings that may be a direct result of utility programs to increase the efficiency of energy use. These policies may include allowing a periodic rate adjustment for investments in end use efficiency or allowing changes in price structure designed to produce additional new revenue.

152 FEA’s objection that conservation resources do not deserve an incentive because installations of supply-side options do not receive any additional payment misses the point that supply-side options receive a return on investment. As currently funded, conservation does not earn a return. However, conservation expenditures can be included in rate base as provided in RCW 80.28.260, which states in relevant part:

> (2) The commission shall consider and may adopt a policy allowing an incentive rate of return on investment in additional programs to improve the efficiency of energy end use or other incentive policies to encourage utility investment in such programs.

153 We conclude that state law and policy clearly support the use of financial incentives to promote a broad array of conservation measures. All of the proposed electric conservation programs provide such incentives and encourage through their design Company efforts to achieve as much cost-effective conservation as possible.

154 After carefully reviewing all of the proposals, we find the Staff design is the most balanced and reasonable. It provides a clear and consistent pattern of rewards for performance and it preserves the current threshold of 16.5 aMW minimum performance for penalty avoidance. By initiating incentive payments when PSE achieves the 18.3 aMW target, we effectively agree with PSE that "[i]t is better policy and more understandable to stakeholders to set a reasonably achievable target and then incent the Company to reach beyond the target".

155 With regard to the disputed program design principles, we find a nine-year average measure life is appropriate. The Company's program already achieves this without excluding individual initiatives that have lives less than nine years. We emphasize that the criterion is that the average measure life of the program be nine years, not that every program or project have a life of nine years.

156 We also agree that the pilot program should be three years long commencing in January 2007 and running through December 2009. The three-year time-frame will permit whatever transition to the requirements of I-937 will be necessary in 2010.

157 We also agree with the principle that savings counted in any given year should be directly tied to actions of the Company in that year. However, it is widely recognized that some conservation programs are inherently multi-year in nature posing challenges to measurement in one year. NEEA, in particular, aims many of its efforts at multi-year market transformation. We would not want to see the Company's support for these beneficial efforts discouraged by tying credit for conservation efforts strictly to the Company's funding of NEEA programs in a given year. At the same time, credit for multi-year conservation efforts should not be double-counted. Consequently, we direct the Company and Staff, in consultation with the CRAG and NEEA, as appropriate, to develop criteria for counting annual incremental savings from PSE's participation in NEEA efforts that reflect the Company's participation in multi-year efforts while protecting against any double-counting of savings.

158 Finally, we decline to order the establishment of a new evaluation group. Evaluation is important in terms of performance measurement and to inform the design of future programs. This is an important function of the CRAG. The CRAG and Staff can draw on the evaluation and studies undertaken by the

Regional Technical Forum, which is also focused on studying performance and program design issues. We expect the results of this pilot program to be professionally evaluated in a cost-effective manner determined by Staff and PSE, with advice from the CRAG.

I. Weather Normalization Methodology

159 Weather normalization is a statistical method used to estimate what customer loads would have been in the test-year if normal weather conditions, measured in terms of temperature, had prevailed. In this case, the Company uses a weather normalization procedure that differs from the method it has used in prior cases. In particular, past weather normalization calculations employed temperature data adjusted to represent a single balance point temperature.[106] In this case, the Company models weather sensitive load using the conventional balance point and additional, lower balance points designed to reflect that buildings are better insulated today than they were in the past.

160 Staff does not object to the use of the proposed, multiple-balance-point model in this case, but urges the Commission to order the Company to perform load research analysis to prove the accuracy of its weather normalization procedure.

161 PSE's methodology appears to be highly reliable, explaining 97 percent of variation in historical aggregate customer load. Moreover, PSE's approach yields a revenue requirement that is $1.4 million lower than it would have been under the prior methodology.

162 It is always possible to improve statistical precision, but the question is to what purpose and at what cost. Staff does not dispute the results PSE achieved for purposes of setting rates. PSE estimates it would cost the Company $3.5 million to fund the study Staff proposes. PSE argues reasonably that if the Commission

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[106] Balance point is the external temperature at which buildings require no auxiliary heating or cooling to maintain the desired internal temperature (the actual indoor temperature will be higher due to retained heat from the occupants, lights, electronic equipment and so forth). Conventionally, 65° F is the balance point temperature used to calculate heating and cooling degree-days. Heating and cooling degree days are calculated over a period of time (typically a year) by adding up the differences between each day's mean daily temperature and the balance point temperature. Thus, for example, three successive winter days with average temperatures of 50°F, 47°F and 52°F include a total of 46 heating degree days (HDD).

orders it to perform the study urged by Staff, it should also approve an additional $3.5 million in revenue requirement to pay for the study.

163 We express no opinion about the finer points of the approach PSE used in its weather normalization analysis, but we are satisfied both by its apparent high level of precision and by Staff's acquiescence to its results that it has proven adequate in this instance to capture "normal" – a concept that is imprecise in any event.[107] We expect that PSE will continue to take advantage of opportunities to improve weather normalization methodology and data, relying on advances such as PSE's widespread use of "smart meters." We will not, however, order PSE to undertake an expensive study that might be interesting on an academic level but is unnecessary to produce results acceptable for purposes of setting rates.

J. Prudence of Resource Acquisitions

164 The Commission evaluates the prudence of resource acquisitions by asking what "a reasonable board of directors and company management [would] have decided given what they knew or reasonably should have known to be true at the time they made a decision."[108] This test applies both to the question of need and the appropriateness of the expenditures.

165 PSE's direct case includes substantial competent evidence[109] showing the need and appropriateness of the Company's expenditures incurred in connection with:

- Acquisition of the Wild Horse wind farm.
- The 20-year purchased power agreement between PSE and OrSumas, LLC.
- Relicensing of the Baker River Hydroelectric Project.
- The 20-year purchased power agreement and related transmission agreement between PSE and Public Utility District No. 1 of Chelan

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[107] We note, for example, the problems inherent in the underlying concept of heating/cooling degree day. Heat requirement is not linear with temperature. Heavily insulated modern buildings have a lower balance point than do older buildings with less insulation. Solar gain reduces the need for heating on sunny days (but not cloudy days), and wind increases it (by an amount that depends on how tightly the building is constructed). People also differ in their opinions about what constitutes a comfortable indoor temperature and, thus, place inconsistent demands on HVAC systems at given outdoor temperatures.
[108] *WUTC v. Puget Sound Power & Light Co.*, Cause No. U-83-54, Fourth Supp. Order at 32 (1984).
[109] *See, e.g.*, Garratt, Exhibit 153HC 3-27; Molander, Exhibit 291HC, 2-17; Olin, Exhibit 351HC 6-29.

County, Washington (including recovery of interest at the net of tax rate of return).

- Acquisition of long term gas pipeline capacity from Duke Energy Trading and Marketing.

No party challenged the prudence of these expenditures. We determine that PSE's acquisition of each of the above-listed resources is prudent and find the associated costs are reasonable for recovery in rates.

FINDINGS OF FACT

166 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

167 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including gas and electrical companies.

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

169 (3) PSE has not carried its burden to show its proposed modifications to the dead band and cost sharing features of its current power cost adjustment mechanism (PCA) are in the public interest.

170 (4) The following investments by PSE were prudent and were made at reasonable costs:

- Acquisition of the Wild Horse wind farm.

- The 20-year purchased power agreement between PSE and OrSumas, LLC.
- Relicensing of the Baker River Hydroelectric Project.
- The 20-year purchased power agreement and related transmission agreement between PSE and Public Utility District No. 1 of Chelan County, Washington (including recovery of interest at the net of tax rate of return).
- Acquisition of long term gas pipeline capacity from Duke Energy Trading and Marketing.

171 (5) PSE, having revised its initial proposal for increased rates during the course of this proceeding, did not show the rates proposed by tariff revisions filed on February 15, 2006, and suspended by prior Commission order, to be fair, just, or reasonable.

172 (6) PSE has demonstrated by substantial competent evidence that its current rates are insufficient to yield reasonable compensation for the electric and gas services it provides in Washington.

173 (7) The record in this proceeding supports a capital structure and costs of capital, which together produce an overall rate of return of 8.40%, as set forth in the body of this Order in Table 5.

174 (8) The Commission's resolution of the disputed issues in this proceeding, coupled with its determination that certain uncontested adjustments are reasonable, result in finding that PSE's natural gas revenue deficiency is $31,259,011 and its electric revenue deficiency is $17,174,242.

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

176 (10) The terms of the multi-party settlement concerning electric rate spread and rate design, and low-income energy assistance, attached to this Order as Appendix A and incorporated by this reference, are consistent with the public interest.

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

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

CONCLUSIONS OF LAW

179 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

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

181 (2) The rates proposed by tariff revisions filed by PSE on February 15, 2006, and suspended by prior Commission order, were not shown to be fair, just or reasonable and should be rejected. *RCW 80.28.010.*

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

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

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

185 (6) The costs of PSE's investments found on the record in this proceeding to have been prudently made and reasonable should be allowed for recovery in rates.

186 (7) PSE should have the opportunity to earn an overall rate of return of 8.40% based on the capital structure and costs of capital set forth in the body of this Order, including a return on equity of 10.40% on an equity share of 44.00%.

187 (8) PSE should be authorized and required to make a compliance filing to recover its revenue deficiency of $31,259,011 for natural gas service and $17,174,242 for electric service. *WAC 480-07-880(1).*

188 (9) The multi-party settlement concerning electric rate spread and rate design, and low-income energy assistance, attached to this Order as Appendix A and incorporated by prior reference, should be approved and adopted.

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

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

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

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

ORDER

THE COMMISSION ORDERS THAT:

193 (1) The proposed tariff revisions PSE filed on February 15, 2006, which were suspended by prior Commission order, are rejected.

194 (2) The multi-party settlement concerning electric rate spread and rate design, and low-income energy assistance, attached as Appendix A and incorporated into this Order by prior reference, is approved and adopted.

195 (3) PSE is authorized and required to file tariff sheets following the effective date of this Order that are necessary and sufficient to effectuate its terms. The required tariff sheets must be filed at least three business days prior to their stated effective date. .

196 (4) Its prior orders approving and otherwise concerning the Company's PCA mechanism are modified to the extent necessary to effectuate the terms of this Final Order.

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

198 (6) The Commission retains jurisdiction to effectuate the terms of this Final Order.

Dated at Olympia, Washington, and effective January 5, 2007.

WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

MARK H. SIDRAN, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

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

APPENDIX A

Partial Settlement Agreement re: Electric Rate Spread, Rate Design and Low Income Energy Assistance

APPENDIX B

Revenue Requirement Stipulation

GLOSSARY