BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-090704** **Docket No. UG-090705** **(*consolidated*)**

INITIAL BRIEF OF PUGET SOUND ENERGY, INC.

FEBRUARY 19, 2010

PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

1. Puget Sound Energy, Inc. ("PSE") respectfully requests that the Commission issue an order approving its request for general rate relief in an amount equal to an annual increase in electric retail revenue of $110,303,620[1] and in natural gas revenue of $28,464,116, which includes a request that the Commission authorize a rate of return on common equity of 10.80% and a capital structure containing 48% common equity.

2. It is undisputed that PSE is facing a critical need for significant investments in new energy resources and new electric and gas system delivery infrastructure in order to meet statutory and regulatory requirements, upgrade aging facilities and serve the needs of a growing customer base. PSE requests financial relief that supports these efforts. The 10.80% return on equity ("ROE") that PSE seeks is consistent with the determinations of other regulatory commissions and the related expectations of the market. It is also consistent with the need to provide financial support during a period of large and increasing under-earnings related to using a historic test year for distribution system investments and operating costs.

3. PSE does not take lightly this request for a rate increase. Other parties have argued that PSE should be cutting back on its costs during these difficult economic times. However, it is not just in difficult economic times that this argument is true; it is good business practice to implement cost containment measures in good times as well as bad. Accordingly, PSE *continually* strives to identify and implement cost-control measures wherever it can, both with respect to capital expenditures and operating expenses. PSE is always concerned about the impact of rate increases on its customers and must weigh this concern with its pubic service

[1] PSE's accepts Commission Staff's deferred balanced filed in their response to Bench Request No. 3 for Mint Farm and Wild Horse Expansion adjusted for carrying costs and 10 year amortization for the Mint Farm deferral; this adjustment reduced PSE's Bench Request No. 3 revenue deficiency by $2,360,912.

requirements to provide high quality, reliable, electric and natural gas services to its customers regardless of economic conditions. Customers' expectations for reliable electric and natural gas service do not decline with the economy; these expectations remain high due to the increased reliance on technology in their homes and businesses. The state of the economy also does not impact the additional costs PSE faces due to new and expanding green power requirements and regulatory compliance requirements, such as those imposed by the North American Electric Reliability Corporation and the Western Electricity Coordinating Council standards.

4. Commission Staff, Public Counsel, and other intervenors in this case have proposed changes to regulatory policy that are unsound and impractical to implement. Their proposals focus on short term rate relief at the expense of a balanced long-term regulatory policy that respects the customers' needs and the Company's opportunity to earn a fair return. These lean economic times, however trying, are not proper justification to abandon time-tested and reasoned approaches to cost recovery. For example:

- Commission Staff, Public Counsel, and the Industrial Customers of Northwest Utilities ("ICNU") propose significant changes to the underlying methodology by which the power cost baseline is set in rate proceedings, despite the fact that the PCA has generally functioned as intended since its inception eight years ago.

- Commission Staff and Public Counsel propose application of "pro forma adjustments" that depart from past Commission decisions and these parties' recommendations in past cases. An example is Commission Staff's disregard of the fact that PSE will owe property taxes during the rate year on new plant put in service after January 1, 2008.

- Public Counsel adopts a short-sighted view of the acquisition of PSE's Mint Farm Generating Station by inappropriately focusing on the up front cost of the resource while ignoring the benefits the plant will provide over its 30-year life.

- FEA's "results oriented" approach to funding pension costs is designed to ensure that the Company under recovers its cost.

5. There is no dispute that the Company has historically under-earned on its regulated return on equity. Absent a significant change in the Company's Multi-Year Plan, the various proposals of Commission Staff, Public Counsel and ICNU would deeply erode the Company's earnings. If adopted, such proposals will make it extremely difficult to acquire new generation resources, replace aging infrastructure to protect customer service and reliability, and comply with ever increasing regulatory standards. The Commission should reject these short-sighted regulatory policies proposed by the parties.

II. LEGAL STANDARDS

6. The ultimate legal question in a general rate case is whether the rates and charges proposed by PSE are fair, just, reasonable, and sufficient.[2] In making these determinations, the Commission is bound by the statutory and constitutional mandate that a regulated utility is entitled to (i) reasonable and sufficient compensation for the service it provides,[3] and (ii) the opportunity to earn "a rate of return sufficient to maintain its financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk."[4]

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

> It is just as important in the eye of the law that the rates shall yield reasonable compensation as it is that they shall be just and reasonable and non-discriminatory from the standpoint of the customer, because unless every rate does yield reasonable compensation, public service companies must resort to discrimination in order to live or must eventually be forced

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[2] RCW 80.28.020; *People's Org. for Wash. Energy Res. v. Wash. Utils. & Transp. Comm'n*, 104 Wn.2d 798, 808 (1985) (en banc) ("*POWER*").
[3] *POWER*, 104 Wn.2d at 808; *Puget Sound Traction Light & Power Co. v. Pub. Serv. Comm'n*, 100 Wn. 329, 334 (1918) (en banc); RCW 80.28.010(1).
[4] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket Nos. UE-991606, *et al.*, Third Supp. Order at ¶ 324 (2000).

> out of business. Every statutory element must be recognized in the fixing of rates, or the result will be to defeat the legislative purpose.[5]

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

> the shareholders of the utility must absorb the disallowed expenses, with a resulting reduction in the actual rate of return earned by them. This means that disallowance of an expense in a rate case has the very real effect, among others, of increasing the risks of investing in the utility.[6]

These concerns should apply with equal force to situations in which the traditional methods utilized by the Commission to set rates result in chronic under-recovery of the levels of revenues and rates of return on equity that the Commission has authorized.

8. Only PSE's proposed relief meets these standards. No other parties' proposal will enable PSE to earn reasonable compensation on its investment and meet its service requirements.

III. PSE'S COST CONTAINMENT EFFORTS

9. PSE is one of the lowest cost providers among investor-owned combined electric and gas utilities in the United States.[7] PSE takes cost containment seriously[8] and has effectively contained or reduced many costs.[9] PSE's procurement team works to obtain favorable pricing and terms through all market conditions.[10] PSE froze officers' salaries to 2009 levels and does not seek recovery of officer incentive pay in this general rate case.[11] The Company has restricted travel.[12] PSE has also worked to increase productivity and efficiencies with some of its new or updated equipment and plans. Even Public Counsel's witness recognizes the efforts

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[5] *Wash. ex rel. Puget Sound Power & Light Co. v. Dep't of Pub. Works of Wash.*, 179 Wn. 461, 466 (1934).
[6] *POWER*, 104 Wn.2d at 811.
[7] *See* Valdman, Exh. No. BAV-3; s*ee also* Valdman, Exh. No. BAV-10CT 11:8-9.
[8] *See* Valdman, Exh. No. BAV-10CT 11:12-13.
[9] *See* Dittmer, Exhibit No. JRD-14.
[10] *See* Valdman, Exh. No. BAV-1T 16:10-17.
[11] *See* Markell, Exh. No. EMM-1CT 31:8-16.
[12] *See* Dittmer, Exh. No. JRD-14 8.

PSE has made to control costs.[13] Many of these efficiencies are realized and reflected during the test year, and PSE expects to limit future cost increases through efficiencies gained from these new technologies; however as history shows this does not mean total costs decrease.[14]

10. It would not be reasonable for the Commission to adopt "austerity adjustments" of the type described by Mr. Dittmer.[15] The austerity adjustments considered by the New York and Hawaii commissions due to the bad economy are inappropriate. Both of these jurisdictions use a forward-looking test year.[16] In contrast, Washington State uses a historic test year, with limited pro forma adjustments. Such a program in this state would guarantee under recovery of costs.

IV. RESOURCES

A. Prudence of Resource Acquisitions

11. In PSE's 2003 Power Cost Only Rate Case proceeding, Docket No. UE-031725, the Commission reaffirmed the standard it applies in reviewing the prudence of power generation asset acquisitions. These standards address the questions of what a reasonable board of directors and company management would decide based on what should have been reasonably known.[17]

12. In addition to this reasonableness standard, the Commission has cited several specific factors that inform the question of whether a utility's decision to acquire a new resource was prudent. The utility must determine that the new resource is necessary.[18] Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When

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[13] *See* Dittmer, Exh. No. JRD-01TC 23:22 – 25:8.
[14] *See* Valdman, TR. 175:2 – 183:18.
[15] *See* Dittmer, TR. 617-620.
[16] Consolidated Edison Company of New York, Inc. used a forward-looking test year. *See* State of New York Public Service Commission, Docket 08-E-0539. Hawaii statutorily requires a forward-looking test year. *See* Haw. Code R. Section 6-61 (2008).
[17] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order No. 12 at ¶ 19, Docket No. UE-031725 (2004).
[18] *See, e.g., Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Nineteenth Supplemental Order at 11, Docket No. UE-921262, *et al.* (1994) (the "1994 Prudence Order").

considering the purchase of a resource, the utility must evaluate that resource against other available resources and against the standard of what it would cost to build the resource itself.[19] The utility must keep its board of directors involved in the purchase decision process and informed about the purchase cost.[20] The utility must keep contemporaneous records that will allow the Commission to evaluate its actions with respect to the decision process.[21] PSE has met these standards and respectfully requests a prudence determination for the resources listed below.

1. Non-Disputed Resources

13. No party challenges the prudence of PSE's acquisition of the following resources: (i) the acquisition of Fredonia Generating Units 3 and 4 and (ii) the expansion of the Wild Horse Wind Facility to add 44 MW of capacity to the facility. Additionally, no party challenges the prudence of PSE's execution of power purchase agreements with the following counterparties: (i) a four-year winter power purchase agreement with Barclays Bank PLC; (ii) a four-year and three-month power purchase agreement with Credit Suisse; (iii) a five-year power purchase agreement with Puget Sound Hydro LLC; (iv) a five-year power purchase agreement with Qualco Energy, LLC[22] and a five-year power purchase agreement with Powerex for Point Roberts.[23] PSE respectfully requests that the Commission determine that PSE acted prudently in acquiring these resources and executing these power purchase agreements.

[19] *See* 1994 Prudence Order at 11.
[20] *See* 1994 Prudence Order at 37, 46.
[21] *See* 1994 Prudence Order at 2, 37, 46.
[22] *See* Harris, Exh. No. KJH-8CT 1:17 – 2:4.
[23] *See* Mills, Exh. No. DEM-9CT 9:10-13; *see also* Mills, Exh. No. DEM-1CT 38:8-9.

2. PSE Acted Prudently in Acquiring the Mint Farm Energy Center

14. Public Counsel is the only party that challenges the prudence of PSE's acquisition of the Mint Farm Energy Center ("Mint Farm").[24] Public Counsel's prudence analysis is incomplete and selectively ignores the evidence presented.

a. PSE Demonstrated a Need to Acquire the Mint Farm Energy Center

15. PSE has extensively documented its need to acquire resources. PSE's 2007 Integrated Resource Plan ("IRP") projected that PSE would need to acquire "nearly 700 aMW of electric resources by 2011, more than 1,600 aMW by 2015, and 2,570 aMW by 2027" to meet the projected base load demand of PSE's customers.[25]

16. Public Counsel cites to a presentation to PSE's Board of Directors dated August 4, 2008, which indicated that Mint Farm Energy Center would create surplus capacity on PSE's system through 2011."[26] Public Counsel then erroneously focuses on the first two years of the 30 plus years of life of the Mint Farm Energy Center and alleges that Mint Farm is more expensive than current market resources while ignoring the total cost benefit of Mint Farm over the plant's life. Public Counsel fails to recognize that plants like the Mint Farm Energy Center "are 'lumpy' in that they become available in large blocks of capacity in a timeframe that can not be perfectly matched to load demand."[27] Mint Farm Energy Center creates a surplus for PSE in 2009 and 2010 on a planning basis only. From an operational perspective, the acquisition of the Mint

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[24] *See* Norwood, Exh. No. SN-1HCT 3.
[25] Harris, Exh. No. KJH-5 8. PSE's 2009 IRP projects that PSE will need to acquire 676 MW of electric resources and energy efficiency by 2012, 1,084 MW by 2015, and 2,453 MW by 2020. These needs include the addition of the Mint Farm Energy Center, the Barclay's 4-year seasonal PPA and reflect the economic downturn and its impact on load. *See* Elsea, Exh. No. WJE-21HCT 5:9 – 7:4
[26] Norwood, Exh. No. SN-1HCT 9:4-6.
[27] Nightingale, Exh. No. DN-1THC 15:19-20.

Farm Energy Center does not create a surplus. Instead it allows PSE to rely less on short-term market purchases to meet load.[28]

b. Quantitative and Qualitative Analyses Support PSE's Acquisition of the Mint Farm Energy Center

17. Public Counsel's suggestion that an alternative proposal was clearly superior to the Mint Farm acquisition fails to reflect the entirety of the evidence in this proceeding. Public Counsel inappropriately focuses on portfolio benefit and portfolio benefit ratio to the exclusion of levelized cost. Public Counsel takes the quantitative analyses out of context. Quantitative analyses alone do not, and should not, dictate the resources that PSE acquires. PSE's resource acquisition decisions also reflect a variety of qualitative and commercial analyses.[29] Public Counsel completely ignores the fact that PSE's decision to acquire the Mint Farm Energy Center does not preclude PSE from pursuing any resource remaining on the Final Short List or the Continuing Investigation List.[30]

c. PSE Provided a Fair Portrait of Mint Farm Energy Center

18. Public Counsel asserts that PSE's presentations to its Board of Directors provided an unduly favorable assessment of the Mint Farm facility.[31] Public Counsel fails to recognize the overall assessment of North American Energy Services Company ("NAES"), the due diligence performed by PSE itself and its other consultants, or to consider the plans that PSE included to address the few areas of concern cited by Public Counsel. Moreover, Public Counsel essentially

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[28] *See* Garratt, TR. 216:4-16.
[29] *See* Garratt, Exh. No. RG-53HCT 17:7 – 22:17.
[30] *See* Garratt, Exh. No. RG-53HCT 23:1 – 28:4.
[31] *See* Norwood, Exh. No. SN-1HCT 13:8-10.

ignores the extensive, 230-page presentation made by PSE to the Board of Directors that fully addresses all aspects of the acquisition, including the few concerns cited by Public Counsel.[32]

d. PSE's Resource Acquisition Process Focuses on Customer Benefits

19. Public Counsel erroneously suggests that PSE selected the acquisition of the Mint Farm Energy Center to add rate base and increase shareholder return.[33] Public Counsel does not (and cannot) provide any evidence to support this assertion. PSE's acquisition process focuses on (i) a resource's compatibility with PSE's resource need to meet load demand as determined in PSE's biannual IRP, (ii) a resource's short-term and long- term capital and operation and maintenance costs, and (iii) a resource's ability to minimize risk in both the short-term and long-term markets.[34] The results of the total quantitative and qualitative analyses demonstrate that the Mint Farm Energy Center benefits PSE's customers.

e. Firm Transmission and Gas Transportation Is Available

20. Public Counsel makes the unfounded suggestion that PSE acquired the Mint Farm Energy Center despite inadequate firm gas transportation capacity and insufficient firm transmission rights.[35] This ignores the fact that PSE held and still holds (i) sufficient firm transportation capacity on the Northwest Pipeline system to ensure delivery of adequate gas supply to Cascade Natural Gas Corporation's distribution system and (ii) sufficient firm distribution capacity on the Cascade Natural Gas Corporation system, when combined with

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[32] *See* Garratt, Exh. No. RG-53HCT 14:17 – 17:6.
[33] *See* Norwood, Exh. No. SN-1HCT 18:13 – 19:5.
[34] *See* Garratt, Exh. No. RG-53HCT 28:14-19.
[35] *See* Norwood, Exh. No. SN-1HCT 16:3-7.

unused firm capacity on such system, to adequately serve the gas requirements of the Mint Farm Energy Center.[36]

21. Mint Farm Energy Center's firm transmission deficit of 3 MW is not a risk to owning the plant. PSE has identified methods to manage this minor issue. In the short-term, existing firm transmission can be used to cover instances when the plant is capable of producing in excess of 293 MW. In the long-term, PSE has submitted a transmission request to BPA under BPA's 2009 Network Open Season to acquire an additional 12 MW of firm transmission.[37]

B. The Mint Farm Energy Center and the Sumas Energy Center Are Baseload Electric Generation that Comply with the Emission Performance Standards

22. The Commission should find that the Mint Farm Energy Center and the Sumas Energy Center are baseload generation that meet the emissions standard set forth in Chapter 80.80 RCW.

23. It is undisputed that the Washington State Department of Ecology confirmed that Mint Farm and Sumas meet the emissions performance standards in RCW 80.80.040. [38] However, Public Counsel challenges the status of Mint Farm as baseload electric generation.[39] Public Counsel erroneously claims 1) Mint Farm is not designed and intended to provide electricity at an annualized plant capacity factor of at least sixty percent, and 2) Mint Farm is not needed and appropriate.

24. Public Counsel's second claim is easily dismissed, as there is no provision in RCW 80.80.060 that mentions need or appropriateness of a power plant. Moreover, as amply demonstrated in this proceeding, the acquisition of Mint Farm was prudent.

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[36] *See* Riding, Exh. No. RCR-6T 2:2 –7:6.
[37] *See* Garratt, Exh. No. RG-53HCT 43:3-6.
[38] *See* Henderson, Exh. No. JMH-5 regarding Mint Farm; *see* Nightingale, Exh. No. DN-2 regarding Sumas.
[39] Public Counsel does not similarly challenge the status of Sumas.

25. Regarding Public Counsel's first claim, in determining whether Mint Farm is baseload generation, the Commission shall consider:

1) the design of the plant, and
2) its intended use, based upon
   a) permits necessary for the operation of the power plant, and
   b) any other matter the commission determines is relevant under the circumstances.[40]

26. Both Mint Farm and Sumas are combined-cycle combustion turbines designed to operate continuously at a baseload capacity factor above 90%.[41] The manufacturer's specifications state that Mint Farm's equipment has the capability to routinely meet and exceed a 60 percent annualized capacity factor.[42] Public Counsel provides no evidence refuting PSE's and Commission Staff's evidence that Mint Farm is indeed designed to operate as baseload generation.

27. Public Counsel claims Mint Farm is not intended to operate as baseload generation,[43] while ignoring such evidence from PSE witnesses Louis E. Odom,[44] W. James Elsea,[45] David E. Mills,[46] and Joey M. Henderson[47] on this point. PSE intends to operate Mint Farm and Sumas as baseload generation whenever it is economically feasible to do so.[48] Mint Farm has achieved a

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[40] RCW 80.80.060(3).
[41] *See* Odom, Exh. No. LEO-1CT 29:3-5; *see also* Odom, Exh. No. LEO-8C 115.
[42] *See* Odom, Exh. No. LEO-8C 115, categorizing continuous operation of Mint Farm, at 8200 hours/year, as "typical" operation.
[43] *See* Norwood, Exh. No. SN-1HCT 28:5-7.
[44] *See* Odom, Exh. No. LEO-1CT 29:1-12.
[45] *See* Elsea, Exh. No. WJE-1HCT 51:16-19.
[46] *See* Mills, Exh. No. DEM-1CT 25-31.
[47] *See* Henderson, Exh. No. JMH-1T 3:3; *see also* Henderson, TR. 403:7-9 and 404:24 – 405:3.
[48] *See* Elsea, Exh. No. WJE-1HCT 51:12-20; *see also* Odom, Exh. No. LEO-1CT 29:11-14 and Mills, Exh. No. DEM-1CT 25-31.

capacity factor greatly exceeding 60% over several months in 2009.[49] Commission Staff witness David Nightingale concurs that Mint Farm and Sumas comply with RCW 80.80.060.[50]

28. Both Mint Farm and Sumas are permitted as baseload generation, which is a key factor determining intent pursuant to RCW 80.80.060(3). Ecology determined that Mint Farm was "designed, intended and permitted to operate as a baseload power plant."[51] Mr. Nightingale confirmed with Ecology that there are no restrictions on the maximum number of hours per year that Mint Farm can operate.[52] Additionally, Mint Farm's air discharge permit allows Mint Farm to operate 365 days per year.[53]

C. PSE's Sale of White River Assets Are Appropriate

29. The Commission should determine that the sale of the White River assets to the Cascade Water Alliance is appropriate. Mr. Paul Wetherbee provided detailed testimony regarding the sale, the alternatives considered by PSE, and the appropriateness of the consideration received,[54] and no party has opposed this requested determination.

V. REGULATORY PROPOSALS FOR POWER COSTS

A. The PCA Mechanism Is Working as Intended

30. The Commission should reject the various methodology changes and adjustments to power costs proposed by the Joint Parties and Public Counsel. These proposals undermine the

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[49] *See* Odom, Exh. No. LEO-13CT 29:14:12-13.
[50] *See* Nightingale, Exh. No. DN-1HCT 19:9-19.
[51] Henderson, Exh. No. JMH-5.
[52] *See* Nightingale, Exh. No. DN-1HCT 44: 1-5.
[53] *See* Henderson, Exh. No. JMH-3 6-8.
[54] *See* Wetherbee, Exh. No. PKW-1T 2-18.

Commission's stated goal to set the power cost baseline rate as close as practicable to what is likely to be experienced during the rate year.[55]

31. The Commission has recognized in recent cases that the PCA and the process by which the power cost baseline rate is set have been working as intended.[56] As Mr. Mills testified: "Over the first seven PCA periods, beginning July 1, 2001, and ending December 31, 2008, PSE's power costs have tracked very closely to the respective allowed power costs . . . . . [P]ower cost under-recoveries have been $6.8 million (or 0.1% of the allowed power costs)."[57] Setting the baseline rate artificially low, as the parties various proposals will do, shifts even more operational risk to the Company and exacerbate its under-recovery of power costs and its already unacceptable level of under-earnings. This is especially troubling given the fact that during the first 11 months of the most recent PCA period (January through November 2009), the Company under-recovered power costs by more than $17 million, and the under recovery for the full 12 months will be even greater using the current methodologies for setting power cost recovery.[58]

B. Regulatory Proposals Relating to Gas for Power Mark-To-Market

1. The Mark-To-Market Adjustment Provides Benefits To Customers

32. The mark-to-market adjustment calculates the difference between the three-month average monthly cost of natural gas used in the AURORA model and the monthly average cost of natural gas for power hedges that have already been transacted for the rate year per the Company's hedging strategy. The mark-to-market adjustment allows PSE to recover costs of

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[55] *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 08 ¶ 22, Docket Nos. UE-060266 & UG-060267 (2007); *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 06 ¶ 108, Docket Nos. UG-040640, *et al.* (2005).
[56] *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 08 ¶ 33 Docket UE-060266; *see also Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 13 ¶ 29, Docket UE-072300 (Jan. 15, 2009).
[57] *See* Mills, Exh. No. DEM-12CT 7:12-15.
[58] *See* Mills, Exh. No. DEM-12CT 8:7-11.

executed hedging contracts that will settle during the rate year.[59] Hedges are not used to speculate on the market; instead they are used strictly as a means to reduce volatility in costs and rates, which protects the customer.[60]

33. No party has previously objected to including hedging contracts in the power cost forecast.[61] Nor did any party object when PSE's rate year power costs were reduced to reflect lower priced gas supply contracts and customers realized a benefit of over $122 million as a result of their inclusion.[62] Nor did any party question the effectiveness of the Company's long-standing hedging program that was in effect when the hedges were entered into. As the evidence demonstrates, customer rates would have been higher over the past several years if rates were set using only forward gas prices.[63]

2. The Joint Parties' Proposal for an Arbitrary Cap on Gas for Power Mark-to-Market Adjustment Should Be Rejected

34. The proposal of an adjustment to mark-to-market costs based upon an arbitrary 80% volume from a static AURORA output exposes PSE and its customers to increased market risk if PSE were to adopt such a policy. In contrast, the existing treatment for gas hedges has resulted in a cumulative benefit to customers.

35. There are several problems with the Joint Parties' proposal to implement a hedging cap. In a rising price scenario it is probable that the Company and its customers would be exposed to higher power costs as a result of implementing an arbitrary 80% cap on AURORA determined

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[59] *See* Mills, Exh. No. DEM-12CT 16:16-17:6.
[60] *See* Mills Exh. No. DEM-12CT 51:11-14.
[61] *See, e.g., Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Settlement Agreement, Att. A, p. 2, line 9, Docket UE-050870 (Aug. 30, 2005).
[62] *See* Mills, Exh. No. DEM-12CT 19:4-15.
[63] *See id.*

gas requirements.[64] Also, Joint Parties price the entire volume of the "removed hedges" using Sumas hub prices even when the volume of trades at the Sumas hub is less than the volume of the "removed hedges".[65] In addition, the parties have made no provision for pricing the AURORA determined gas needs in excess of the 80% cap.[66]

36. ICNU erroneously seeks to distinguish long-term mark-to-market contracts and exclude these from the analysis of customer benefits as they were not executed as part of the Company's current hedging strategy. Customers have benefited by approximately $122.1 million[67] over the past decade because these mark-to-market contracts (both long-term and short-term contracts) have been included in the calculation of the power cost baseline rate in each of the recent PSE rate proceedings.[68] Parties have had the opportunity to review this program in several general rate cases, power cost only rate cases, and in the PCA compliance report, yet there has been no objection. It is only now, when the mark-to-market adjustment reflects a cost rather than a benefit to customers, that parties question the inclusion of the mark-to-market adjustment in determining power costs. Allowing a mark-to-market adjustment in the baseline power cost calculation when the adjustment benefits customers, then removing the mark-to-market adjustment in years when gas prices are declining, creates unbalanced and arbitrary regulatory policy. The baseline rate should continue to reflect the gas hedges that have been executed under PSE's hedging program, rather than relying on AURORA's static power costs forecast.[69]

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[64] *See* Mills, Exh. No. DEM-12CT, 17:20 – 18:4.
[65] *See* Mills, Exh. No. DEM-12CT 22:11-15.
[66] *See* Mills, Exh. No. DEM-12CT 22:7-10.
[67] *See* Mills, Exh. No. DEM-12CT 19:10-13.
[68] *See* Mills, TR. 778:19-23Exh. No. DEM-12CT:7-13.
[69] *See* Mills, TR. 776:6-10; 777:24-778:20; 779:19-23.

3. The Mark-to-Market Cost Rider Is Inappropriate

37. Both the Joint Parties' proposed rider and Public Counsel's proposed credit to remove mark-to-market costs result in no recovery of mark-to-market costs after March 2011 unless PSE resets rates before that time.[70] As PSE removes the market volatility from its power portfolio by hedging the price of gas for power, there will always be hedges and a mark-to-market cost or benefit of the gas for power hedges transacted to fix the cost of gas for power.[71] It would be arbitrary to exclude one component of the power cost calculation from recovery after the rate year, especially without considering how all other power costs have changed.[72]

C. All Available Hydro Data Should Be Used

1. Hydro Filtering

38. The Joint Parties' proposal to remove 40% of hydro data through a filtering process disregards the Commission's objectives to use all available hydro data[73] and to set the power cost baseline rate as close as practicable to what is likely to be experienced during the rate year.[74] The Joint Parties' proposal would eliminate 20 years of hydro data, effectively rendering the Commission ordered 50-year hydro dataset into a 30-year dataset. The Joint Parties concede that their proposed hydro filtering adjustment, which purports to exclude "outlier" water years from the PCA, has no statistical basis.[75] As Dr. Dubin testified: "Filtering is a scientific method

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[70] *See* Mills, Exh. No. DEM-12CT 50:6-17.
[71] *See* Mills, Exh. No. DEM-12CT 51:11-22.
[72] *See* Mills, Exh. No. DEM-12CT 50:20-51:10; s*ee also* Story, Exh. No. JHS-14T 18:9-10.
[73] *See* Dubin, Exh. No. JAD-1T 14:14-17; *see also Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 06 ¶ 131, Docket Nos. UG-040640, *et al.* (2005).
[74] *See also Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 06 ¶ 106-08, Docket Nos. UG-040640, *et al.* (2005)
[75] *See* Joint Testimony, Exh. No. JT-1CT 11:19-20 ("The choice of a one standard deviation filter was not based on a scientific study of any kind.").

subject to scientific scrutiny and, under scrutiny, [the Joint Parties'] filtering the hydro record has no scientific support."[76]

39. In contrast, PSE provided statistical evidence regarding the importance of using all available hydro data and provided evidence as to the flaws in the hydro filtering adjustment.[77] Chief among these flaws is the Joint Parties' exclusion of 40% of the data, which artificially increases hydro availability.[78] As the Commission previously recognized after examining a fully developed hydro record, these water years are normally distributed,2[79] because there are no statistically significant outliers, trimming of means and censoring of data are improper.[80]

40. The Joint Parties claim that hydro filtering will result in power costs that are "more normally expected to occur" and will "not be biased one way or the other"[81] but such results are not accomplished by trimming 40% of the relevant data from consideration. In fact, the Joint Parties would consider PSE's extreme loss of Mid-Columbia ("Mid-C") hydro generation for three of the past seven years as "outliers" and "the review and recovery of costs associated with those years, if indeed they do occur," would be relegated "to the annual PCA review when all costs are known."[82] Actual events contradict Joint Parties claim that filtering hydro data benefits "ratepayers by more appropriately realigning risk sharing," because in these three "outlier" years, customers were protected by the PCA mechanism in that PSE absorbed $44.9 million or 90% of the PCA cost under-recoveries.[83]

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[76] JAD-TI 33:4-5.
[77] *See* Mills, Exh. No. DEM-12CT 38:18-40:14; *see* Dubin Exh. No. JAD-1T 4-24.
[78] *See* Dubin, Exh. No. JAD-1T 13:17-18, 15:11-14.
[79] *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 06 ¶¶ 128-131, Docket Nos. UG-040640, *et al.* (2005).
[80] *See* Dubin, Exh. No. JAD-1T 14:10-15:14.
[81] Joint Testimony, Exh. No. JT-1CT 8:18-23.
[82] Joint Testimony, Exh. No. JT-1CT 8:1-5, 12:1.
[83] *See* Mills, Exh. No. DEM-12CT 33:17-35:9.

41. Moreover, the Joint Parties' hydro filtering adjustment improperly utilizes the entire Mid-C generation for each of the water years without considering the fact that PSE has varying contractual shares of the generation from the Mid-C hydro projects. It is PSE's share of the generation of the Mid-C projects generation that directly affects PSE's power costs in the AURORA model runs, not the total Mid-C projects generation.[84]

42. Contrary to the Joint Parties assertion that the Commission has favored water filtering, the Commission has never before decided this issue in a litigated case for a Company with a PCA mechanism that has the history outlined above showing that such an adjustment is unnecessary.

2. Rolling 50-Year Average Hydro

43. The Commission should reject Public Counsel's proposal to use a rolling 50-year average of hydro data for the years 1949-1998. The Commission has previously rejected the use of a rolling average[85] because it can introduce swings and variability into the hydro forecast that are not in fact present.[86] The proper way to incorporate the additional 20 years of hydro data would be to add it to the 50 years of data that has previously been used to create a 70-year dataset.[87]

D. Other Regulatory Proposals and Adjustments Are One-Sided

1. Gas Trigger Mechanism

44. Public Counsel's proposal to "trigger" a power cost reduction whenever gas prices drop by 15% or more from the gas prices reflected in rates is overly simplistic. It focuses on natural gas prices without regard to any other variable that affects projected rate year power costs. For

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[84] *See* Mills, Exh. No. DEM-12CT 39:20-40:14.
[85] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 06 ¶¶ 128, 131, Docket Nos. UG-040640, *et al.* (2005).
[86] *See* Dubin, Exh. No. JAD-1T 29:1-33:7.
[87] *See* Dubin, Exh. No. JAD-1T 31:9-17.

example, gas prices have decreased 30% from PSE's last general rate case filing, but PSE's current power costs are higher than what are actually included in rates.[88] The complex interactions of the resources used to serve the customers cannot be simplified by adjusting one component of the power costs, and is one of the reasons all the components of power costs are used in setting the PCA baseline rate.[89]

2. Off System Sales of Power

45. The Commission should reject Public Counsel's argument that the off system sales of power modeled by AURORA should be adjusted. Public Counsel's proposal fails to recognize the difference between the use of AURORA modeling for setting rates—including modeling off system sales of power—and the actual market transactions (sales and purchases) that occur. Mr. Mills testified to the process by which rate year market purchases and sales are determined in the AURORA model and why forecast transactions differ from actual transactions.[90] This use of AURORA in modeling transactions for rate purposes is the same process PSE has historically used,[91] and the Commission has previously endorsed.[92]

46. Additionally, Public Counsel's proposal addresses only one side of the market transactions modeled by AURORA—market sales. It ignores the fact that actual market purchases are also much higher than the forecast purchases modeled in AURORA,[93] creating the *total* actual net market costs (market purchases less sales) that are much greater than forecast, on average more than 1.7 million MWHs or $83.1 million greater than forecast over the past six rate

[88] *See* Mills, Exh. No. DEM-12CT 52:2-53:4.
[89] *See* Story, Exh. No. JHS-14T 19:5-11.
[90] *See* Mills, Exh. No. DEM-12CT 46:3 – 48:9.
[91] *See* Mills, Exh. No. DEM-12CT 46:3-14; 48:7-49:1.
[92] *See, e.g., Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 08 ¶ 113, Docket Nos. UE-060266 & UG-060267 (2007).
[93] *See* Mills, TR. 750:9-21.

cases.[94] Further, Public Counsel's proposed adjustment then uses an arbitrary average margin of $2.00 per MWh for secondary sales and multiplies this by a proxy for rate year sales.[95] In sum, Public Counsel's proposed adjustment lacks any sound foundation and should be rejected.

47. The Commission should also reject Public Counsel's request that PSE track off system sale revenues and margins. As Mr. Mills testified, such a requirement would require significant upgrades and modifications to PSE's information systems.[96]

VI. CAPITAL STRUCTURE AND COST OF CAPITAL

A. Introduction

48. Table 1 below presents PSE's proposed capital structure and cost of capital:

TABLE 1
PSE's Proposed Capital Structure and Cost of Capital

Component	Ratio	Cost Rate	Weighted Cost	After Tax
Common Equity	48.00%	10.80%	5.18%	5.18%
Long-Term Debt	48.05%	6.70%	3.22%	2.09%
Short-Term Debt	3.95%	2.47%	0.10%	0.07%
Total	**100.00%**	**N/A**	**8.50%**	**7.33%**

Each of these elements of PSE's proposed capital structure and cost of capital is discussed below.

B. PSE's Proposed Capital Structure That Contains 48% Common Equity Is Reasonable and Properly Balances Safety and Economy

49. PSE has proposed a capital structure that consists of 48.00% common equity.[97] This proposed pro forma capital structure reflects average capital structure ratios that will support utility operations during the rate year.[98] PSE's proposed common equity component is

[94] *See* Mills, Exh. No. DEM-12CT 46:15-48:2.
[95] *See* Mills, Exh. No. DEM-12CT 48:19-49:7.
[96] *See* Mills, Exh. No. DEM-12CT 49:12-19.
[97] *See* Gaines, Exh. No. DEG-5C 1; Gaines, Exh. No. DEG-16 1.
[98] *See* Gaines, Exh. No. DEG-1T 12:6-7; Gaines, Exh. No. DEG-11HCT 2:14-16; *see generally* Gaines, Exh. No.

commensurate with the average common equity ratio of 48.85% approved by state regulatory commissions for ratemaking purposes during the period from January 1, 2008 through August 31, 2009.[99]

50. PSE based its methodology in calculating its proposed pro forma capital structure on the approach used by the Commission in PSE's 2004 general rate case:

> Our goal in this proceeding should be to set the Company's equity ratio at the level that the evidence shows is most likely to prevail, on average, over the course of the rate year.[100]

This methodology produces a capital structure with less common equity than the methodology used by the Commission in PSE's 2006 general rate case.[101] If the 2006 methodology is used, PSE's common equity component would exceed 50%.[102] PSE's proposed pro forma capital structure is reasonable and strikes a fair balance between interests of safety and economy.[103]

51. Commission Staff and Public Counsel have proposed hypothetical capital structures with common equity ratios of 45%[104] and 43%,[105] respectively. These hypothetical capital structures contain substantially less common equity than (i) the common equity ratio currently in PSE's rates (46%), (ii) the current actual common equity ratio that supports utility operations (over 50%); (iii) the common equity ratio that PSE projects will be employed, on average, during

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DEG-5C.

[99] *See* Gaines, Exh. No. DEG-13 3.

[100] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 06 at ¶ 40, Docket Nos. UG-040640, *et al.* (2005).

[101] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 08 at ¶ 80, Docket Nos. UE-060266 & UG-060267 (2007). The Commission based the capital structure on PSE's *actual* common equity share that reflected a "known change from test-year figures."

[102] *See* Gaines, Exh. No. DEG-11HCT 7:7-8 (stating that "PSE's regulated common equity ratio was 52.9% on March 31, 2009").

[103] *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 06 at ¶ 27, Docket Nos. UG-040640, *et al*. (2005) (indicating that the capital structure for ratemaking purposes must be reasonable and strike a fair balance between safety and economy).

[104] *See* Parcell, Exh. No. DCP-1T 3:4.

[105] *See* Hill, Exh. No. SGH-1HCT 19:3-6 Table I.

the rate year (48%); and (iv) the average common equity ratio recently approved by state regulatory commissions for ratemaking purposes (48.85%).

52. Commission Staff asserts that its recommended common equity ratio of 45% is "the same capital structure ratios requested by PSE in prior rate cases" and argues that such ratio "is similar to that of the industry-wide electric and combination electric utilities . . . ."[106] This suggested common equity ratio is, by its very terms, backwards-looking, does not meet the definition of what is known and measurable, and does not reflect the $805.3 million of equity invested in PSE by Puget Energy, Inc. since the commencement of PSE's last general rate proceeding.[107] Moreover, Commission Staff's suggested comparison is misleading because, as Commission Staff concedes, it compares the common equity ratio of PSE for ratemaking to the "per books" capital structures of other utilities and reflects "consolidated holding companies."[108] A more appropriate comparison would be to compare the common equity ratio requested by PSE in this proceeding (48.00%) to the average common equity ratio recently approved by state regulatory commissions for ratemaking purposes (48.85%).[109]

53. Public Counsel fails to offer any justification for its proposed common equity ratio of 43% other than such common equity ratio is the same recommendation made by Public Counsel in PSE's last general rate proceeding and "is higher than the average common equity ratio Puget has actually used over the last few years . . . ."[110] Public Counsel provides no explanation as to why it would be appropriate to ignore PSE's current capital structure, which contains a common equity component that exceeds even PSE's request. Neither Commission Staff's nor Public

[106] Parcell, Exh. No. DCP-1T 25:11-14.
[107] *See* Gaines, Exh. No. DG-11HCT 3:13-16.
[108] Gaines, Exh. No. DEG-12 1.
[109] *See* Gaines, Exh. No. DEG-13 3 (reflecting a period between January 1, 2008, through August 31, 2009); *see generally* Gaines, Exh. No. DEG-11HCT 3:6 – 7:15.
[110] Hill, Exh. No. SGH-1HCT 18:13-14.

Counsel's proposals meet the Commission's goal to set the equity ratio at the level that the evidence shows is most likely to prevail, on average, over the course of the rate year."[111]

C. PSE's Proposed Rate of Return Is Fair, Just, Reasonable and Sufficient

54. Multiple orders of this Commission have provided the following formulation with regard to the appropriate rate of return:

> A utility is entitled to the opportunity to earn a rate of return sufficient to maintain its financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk.[112]

55. Similarly, several decisions of the U.S. Supreme Court require that this Commission's decision allow a utility the opportunity to earn a ROE that is: (i) sufficient to assure confidence in the Company's financial integrity and maintain the Company's creditworthiness, (ii) sufficient to maintain a utility's ability to attract capital on reasonable terms; and (iii) commensurate with returns on investments in other firms having corresponding risks.[113]

1. PSE's Proposed Cost of Equity of 10.80% is Reasonable

56. Dr. Morin, the cost of equity witness for PSE, employs three market-based methodologies--the Discounted Cash Flow ("DCF") Model, the Capital Asset Pricing Model ("CAPM") and the Risk Premium—to provide estimates of the return required by investors on

[111] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 06 at ¶ 40, Docket Nos. UG-040640, *et al*. (2005).
[112] *See, e.g., Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Third Supp. Order at ¶ 324, Docket Nos. UE-991606 & UG-991607 (2000); *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Eleventh Supp. Order at 25, Docket Nos. UE-920433, *et al.* (1993); *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Second Supp. Order at 26, Docket No. U-86-02 (1986).
[113] *See Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *In re Permian Area Basin Rate Cases*, 390 U.S. 747 (1968); *Fed. Power Comm'n v. Memphis Light, Gas & Water Div.*, 411 U.S. 458 (1973); *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989).

the common equity capital committed to PSE. Based on Dr. Morin's analysis of the DCF and Risk Premium,[114] the appropriate ROE for PSE is 10.8%.

57. It is important to note that Dr. Morin's recommend ROE range is consistent with both the average allowed ROEs in 2008, as reported by AUS Utility Reports, for combination electric and natural gas utilities (10.74%) and for electric utilities (10.75%).[115] The fact that the Commission has previously approved ROE below comparables does not make Dr. Morin's calculations wrong.

58. As shown below, Mr. Parcell's recommended ROE of 10.0% is substantially below both the average allowed ROE within the utility industry and the average allowed ROE of 10.59% of the utilities that comprise Mr. Parcell's comparable group of utilities: [116]

TABLE 2
Mr. Parcell's Comparable Group ROEs

Allegheny Energy, Inc.	10.46%
Avista Corporation	10.20%
Cleco Corporation	11.25%
Empire District Electric Co.	10.80%
Great Plains Energy Incorporated	10.45%
Hawaiian Electric Industries, Inc.	10.82%
Pinnacle West Capital Corp.	10.75%
Westar Energy, Inc.	10.00%
AVERAGE	**10.59%**

Similarly, Mr. Hill's recommended ROE of 9.5% for PSE is substantially below the average allowed ROE of 10.61% of the utilities that comprise Mr. Hill's comparable group of utilities:[117]

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[114] As discussed below, Dr. Morin, Mr. Parcell and Mr. Hill agree that the CAPM is not an appropriate methodology in the current economic climate.
[115] *See* Gaines, Exh. No. DEG-14 12-13.
[116] *Id.*
[117] *Id.*

TABLE 3
Mr. Hill's Comparable Proxy Group ROEs

American Electric Power Co.	10.71%
Central Vermont Public Serv. Corp.	10.71%
Cleco Corporation	11.25%
Empire District Electric Co.	10.80%
Entergy Corporation	10.83%
FirstEnergy Corporation	10.67%
Hawaiian Electric Industries, Inc.	10.82%
IDACORP, Inc.	10.50%
Northeast Utilities	9.72%
Pinnacle West Capital Corp.	10.75%
Westar Energy, Inc.	10.00%
AVERAGE	**10.61%**

If the Commission were to accept Mr. Parcell's and Mr. Hill's ROE recommendations of 9.5% and 10.0%, respectively, then PSE would have among the lowest allowed ROEs in the utility industry.

a. DCF Analyses Generate an Average ROE of 10.8%

59. Dr. Morin properly used analysts' long-term growth forecasts contained in Zacks and Value Line as proxies for investors' growth expectations in applying the DCF model.[118] Dr. Morin's DCF analysis provides a range of ROE estimates for PSE that, without flotation costs, has a low of 10.3%, an average of 10.8%, and a high of 11.3%.[119]

60. Both Mr. Parcell and Mr. Hill rely in error on the sustainable (or retention) growth method to determine the growth component of DCF. The sustainable growth methodology contains a logical contradiction—it assumes a ROE in a regulatory process that is designed to

[118] *See* Morin, Exh. No. RAM-1T 45:5-11. Dr. Morin applied these long-term growth forecasts to two proxies for PSE: (i) a group of investment-grade dividend-paying integrated electric utilities and (ii) a group consisting of the electric utilities that make up S&P's Electric Utility Index. *See* Morin, Exh. RAM-1T 49:16-18.
[119] *See* PSE's Response to Bench Request No. 7, Exh. No. B-7.

estimate the fair and reasonable ROE.[120] Additionally, both Mr. Parcell and Mr. Hill erroneously rely on historical growth rates in arriving at proxies for the DCF growth forecast component. In the energy industry historical growth rates have little relevance as proxies for long-term growth forecasts.[121] Moreover, historical growth rates are largely redundant because such historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model.[122] Dr. Morin's testimony describes the errors in the growth forecasts of the DCF analyses of Mr. Parcell and Mr. Hill that result in a downward bias in DCF cost of equity estimates of 150 basis points for Mr. Parcell and 100 basis points for Mr. Hill.[123]

b. The Commission Should Give No Weight To CAPM Results

61. Although Dr. Morin, Mr. Parcell, and Mr. Hill each employs a capital asset pricing model analysis (or a variation of such model) in determining a proposed return on equity for PSE, each expresses concerns regarding the validity of the results generated by the CAPM in light of current economic conditions. First, CAPM analyses currently generate projected costs of equity that are not significantly above the cost of new debt capital and likely understate the cost of equity capital during unsettled capital market conditions. Second, the betas employed in the CAPM analysis are estimates based on a five-year historical periods, and the impact of the ongoing financial crisis is not yet fully captured in the estimates. Finally, spreads between costs of capital for private companies and government interest rates have diverged substantially following the Federal Reserve's expansionary policies designed to jumpstart the stalled

[120] Moreover, empirical finance literature demonstrates that the sustainable growth rate technique is a very poor explanatory variable of market value and is not correlated significantly to measures of value, such as stock price and price/earnings ratios. *See* Morin, Exh. No. RAM-19T 12:3 – 13:7.
[121] *See* Morin, Exh. No. RAM-19T 14:14-15.
[122] *See* Morin, Exh. No. RAM-19T 14:14-18.
[123] *See* Morin, Exh. No. RAM-19T 14:15-18.

economy.[124] Given this anomaly between actual market costs and projections based on CAPM analyses, the Commission should give no weight to this analysis.

c. Historical Risk Premiums Suggest an ROE of 10.34%

62. Dr. Morin bases his historical risk premium of 6.1% for the utility industry on an annual time series analysis from 1931 to 2007 applied to the utility industry as a whole, using the S&P Utility Index as an industry proxy.[125] Recent data suggest a yield of 4.5% on long-term Treasury bonds.[126] Therefore, the implied cost of equity for the average risk utility from the historical risk premium methodology is approximately 10.64% with flotation costs[127] and 10.34% without flotation costs.[128] If, as Value Line projects,[129] yields on long-term Treasury bonds increase to 5.0% by the end of 2010, the implied cost of equity for the average risk utility from the historical risk premium methodology would be 10.84% without flotation costs.

63. Mr. Hill's concern that Dr. Morin's historical risk premium analysis relied on the S&P Utility Index instead of the Moody's Electric Index, on which Dr. Morin relied in the past[130] is a red herring. Following the acquisition of Moody's by Mergent in 2002, publication of the electric utility index was discontinued. Therefore, Dr. Morin relied on the S&P Utility Index instead of the Moody's Index to ensure continuity and timeliness of the risk premium data.[131] Moreover, the results using the S&P Index are not materially different from those using the discontinued Moody's index.[132]

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[124] *See* Morin, Exh. No. RAM-19T 45:11-13.
[125] *See* Morin, Exh. No. RAM-1T 38:17-19.
[126] *See* Morin, Exh. No. RAM-19T 46:7-8.
[127] *See* Morin, Exh. No. RAM-19T 56:10.
[128] *See* PSE's Response to Bench Request No. 6, Exh. B-6.
[129] *See* Hill, Exh. No. SGH-1HCT 27:13-15.
[130] *See* Hill, Exh. No. SGH-1HCT 63:15-24.
[131] *See* Morin, Exh. No. RAM-19T 35:3-18.
[132] *See* Morin, Exh. No. RAM-1T 39:9-17.

64. Mr. Hill also expresses concern with Dr. Morin's historical risk premium analysis because Dr. Morin relied on long-term utility bond yields instead of long-term Treasury bond yields onto which the risk premium is added.[133] However, long-term utility bond yields reflect costs of capital for utilities better than long-term Treasury bond yields in the current financial environment, given the divergence in corporate bond and Treasury bond yields.[134]

2. The Appropriate Cost of Long-Term Debt is 6.70%

65. PSE and Public Counsel agree that the appropriate cost of long-term debt for PSE is PSE's embedded cost of long-term debt of 6.70%.[135] Commission Staff, however, proposes a cost of long-term debt of 6.48%.[136] The Commission should reject Commission Staff's proposed cost of long-term debt because Commission Staff arbitrarily uses the interest rate on PSE's most recent senior secured note issue. This rate represents the lowest coupon that PSE ever received on a 30-year senior secured note issue, and Commission Staff fails to produce any evidence that PSE could issue bonds at such a low rate in the future. Indeed, PSE has projected coupon rates of 6.72% and 6.86% for its next two future bond issues, and these coupon rates are very close to the embedded cost of long-term debt of 6.70%.[137]

66. PSE, Commission Staff, and Public Counsel agree that the appropriate cost of short-term debt is PSE's embedded cost of short-term debt of 2.47%.[138]

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[133] *See* Hill, Exh. No. SGH-1HCT 63:1-64:24.
[134] See Morin, Exh. No. RAM-19T 36:9-18.
[135] *See* Gaines, Exh. No. DEG-9T 14:10; *see also* Gaines, Exh. No. DEG-10C 1:9 (column (D)); *see also* Gaines, Exh. No. DEG-11HCT 21:Table 3; *see also* Hill, Exh. No. SGH-1THC 19:1-6.
[136] *See* Parcell, Exh. No. DCP-1T 28:17 – 29:2; *see also* Parcell, Exh. No. DCP-3.
[137] *See* Gaines, Exh. No. DEG-11CT 19:10-12.
[138] *See* Gaines, Exh. No. DEG-1T 23:11-12; Gaines, Exh. No. DEG-5C 3:16 (column (F)); Gaines, Exh. No. DEG-11HCT 21:Table 3; Parcell, Exh. No. DCP-1T 4:6-7; Hill, Exh. No. SGH-1THC 19:1-6 Table I.

VII. REVENUE REQUIREMENTS

A. Pro Forma Adjustments

67. PSE's application of the Commission rule regarding pro forma adjustments is consistent with the Commission's application of this rule in prior cases. WAC 480-07 510(3)(iii) defines pro forma adjustments as follows:

> Pro forma adjustments give effect for the test period to all known and measurable changes that are not offset by other factors. The work papers must identify dollar values and underlying reasons for each proposed pro forma adjustment.

68. The Commission has recognized that the application of this definition may vary depending on the particular pro forma adjustment at issue. In some situations the definition is met when the company provides a reasonable estimate, based on its expertise.[139] There are many items that are estimates such as depreciation, weather normalization, line losses, power costs,[140] property taxes, rate year load, cost of service allocations and rate of return. In addition, the Commission has allowed, and Commission Staff has endorsed, pro forma adjustments for new plant that is scheduled to go into service coincident with the issuance of a Commission order approving the plant.[141]

69. Despite this long history of allowing the use of reasonable estimates and projections, Commission Staff and Public Counsel now endorse a restrictive application of pro forma

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[139] *Wash. Utils. & Transp. Comm'n v. Wash Natural Gas*, 23 P.U.R.4th 184, 194 Docket No. U-77-47 (1977) (allowing pro forma adjustment based on estimate of leak repairs required over a five year period due to newly enacted rules on classification of leaks).

[140] *Wash. Utils. & Transp. Comm'n v. v. Puget Sound Energy, Inc.*, Order 06 at ¶ 108, Docket UG-040640 *et al.* (2005) ("[P]ower 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.").

[141] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 12 at ¶ 63, Docket No. UE-031725 (2004) ("PSE has carried its burden to show that the costs the Company proposes to include in rates for the PCORC rate period . . . are reasonable."). *See also* Story, Exh. No. JHS-14T 9:9-12-4 (discussing Commission Staff's approval of pro forma adjustments for new plant in service in PSE's 2007 rate case, in which PSE relied on projections and estimates due to lack of 12 month operating data).

adjustments that deviates from prior Commission precedent. This is particularly true with respect to pro forma adjustments relating to power costs and new plant placed in service during the test year. The Commission should stand by its prior decisions and reject the restrictive application of pro forma adjustments as proposed by Commission Staff and Public Counsel.

B. Contested Electric and Combined Electric and Gas Restating and Pro Forma Adjustments

70. Appendix A lists the contested electric adjustments and associated differences in net operating income ("NOI") and rate base. Each of these contested electric and combined electric and gas restating and pro forma adjustments is discussed below.

1. Revenue and Expense (Adjustments 9.02 and 10.02)[142]

a. The Conservation Phase-In Adjustment

71. PSE's conservation phase-in adjustment corrects test year loads to reflect the Company sponsored conservation that was installed over the course of the test year.[143] This adjustment falls within the definition of annualizing restating adjustments.[144] The Company loses revenue when load is reduced through conservation, and this adjustment mitigates that loss.

72. The adjustment is consistent with Congress' instruction to the states in the American Recovery and Reinvestment Act of 2009, in order to secure additional energy efficiency block grant funding:

> The applicable State regulatory authority will seek to implement… a general policy that ensures that *utility financial incentives are aligned with helping their customers use energy more efficiently* ….[145]

[142] The referenced adjustment numbering in each title is from PSE's Response to Bench Request No. 3, Exh. No. B-3.
[143] *See* Piliaris, Exh. No. JAP 1T 18:7-17.
[144] *See* Piliaris, Exh. No. JAP-1T 19:19-21:5.
[145] American Recovery and Reinvestment Act of 2009, Section 410, Additional State Energy Grants. (emphasis added).

PSE's adjustment takes a small step in this direction. PSE is not the first to propose a mechanism to remove disincentives. Many other jurisdictions have approved lost margin recovery mechanisms or other programs to remove disincentives to promote conservation.[146]

73. Commission Staff incorrectly claims that the conservation phase-in adjustment does not take into account purported offsetting factors.[147] Commission Staff does not have specific examples of such cost reductions but merely points to general costs such as labor or maintenance that might be mitigated as a reason to completely reject PSE's proposal.[148] PSE has properly included the impact for power and gas supply savings associated with this adjustment. Conservation savings do not affect any of the other Company's short-run costs that are used in the development of its base rates as conservation does not reduce the amount of transmission or distribution facilities, or the number of employees needed to maintain these facilities, and it does not reduce customer-related costs.[149]

74. Public Counsel's argument that other factors, in addition to conservation, affect sales volume misses the point. In Public Counsel's view, if loads are increasing in general, there is no harm to the utility, even if mandated conservation decreases PSE's load from what it would have

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[146] *See, e.g., In re Application of Carolina Power & Light Co., Inc. for the Establishment of Procedures for DSM/EE Programs*, Order Approving DSM/EE Application, Docket No. 2008-251-E (S.C. Pub. Serv. Comm'n 2009); *In re Application by Carolina Power & Light Co. for Approval of Demand Side Mgmt. and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Comm'n Rule R8-69*, Order Approving Agreement and Stipulation of Partial Settlement, Subject to Certain Comm'n Required Modifications, Docket No. E-2, Sub 931 (N.C. Utils. Comm'n 2009); *Application of Oklahoma Gas and Elec. Co. for an Order of the Comm'n Granting the Recovery of Costs Associated with its Quick Start Demand Programs and Authorizing a Recovery Rider*, Order No. 556179, Docket No. PUD 200800059 (Okla. Corp. Comm'n 2008); *In re Application for Recovery of Costs, Lost Margin, and Performance Incentive Associated with the Implementation of Elec. Residential Demand Side Mgmt. Programs by the Cincinnati Gas and Elec. Co.*, Finding and Order, Docket No. 06-91-EL-UNC et. al. (Ohio Pub. Utils. Comm'n 2007).

[147] *See* Parvinen, Exh. No. MPP-1T 14.

[148] *See* Parvinen, Exh. No. MPP-1T 14.

[149] *See* Piliaris, Exh. No. JAP-5T 6:7-7:15.

been absent the conservation requirement. Whether or not loads are increasing is irrelevant; PSE would have had greater sales to cover increasing costs if conservation had not reduced load.[150]

75. Commission Staff's argument that PSE's conservation savings during the test year have not undergone sufficiently rigorous review is disingenuous, given the fact that the Commission has specifically approved PSE's expected conservation.[151] Mr. Parvinen concedes that the deemed savings come from independent sources and are routinely used for program planning and for calculations of cost-effectiveness.[152] The measurement and evaluation of the Company's savings are consistent with industry standard.[153] Although PSE has performed certain additional post-installation analyses of conservation savings as part of the evaluation of its energy efficiency incentive pilot program,[154] such post installation analyses are above and beyond the "known and measurable" savings that is the relevant standard for this adjustment.

b. Public Counsel Improperly Removes Equity Return on the Mint Farm Generating Station

76. As demonstrated in this proceeding and discussed above, PSE acted prudently in acquiring the Mint Farm Generating Station. Accordingly, the Commission should reject Public Counsels' removal of the equity return on the Mint Farm Generating Station.[155]

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[150] *See* Piliaris, Exh. No. JAP-5T 21:14-22:2.
[151] *See, e.g.*, Commission Staff Open Meeting Memoranda, Docket Nos. UE-090314 and UE-080389.
[152] *See* Parvinen, Exh. No. MPP-1T 16:16-19.
[153] *See* Piliaris, JAP-5T 10:16-18.
[154] *See* Piliaris, TR. 555:18-22.
[155] This appears in Public Counsel's first attachment to its response to Bench Request No. 3, Exh. No. B-4, 50:31. Public Counsel did not assign a specific adjustment number.

2. Power Cost Adjustment (Adjustment 10.03)

a. Uncontested Power Cost Adjustments

77. No party has disputed the Company's correction to upper and lower Baker generation or its updates to Grant and Chelan Mid-C budgets set forth in PSE's rebuttal case[156] and these should be accepted by the Commission.

b. Regulatory Proposals for Power Cost Adjustments

78. Please see Section V above for a discussion of the following regulatory proposals associated with the Power Cost Adjustment: (i) the Gas for Power Mark-to-Market Adjustment; (ii) the Gas Trigger Mechanism; (iii) Hydro Filtering; (iv) Rolling 50-Year Average Hydro; and (v) Off System Sales of Power

c. Jackson Prairie Storage Capacity

79. PSE took a three-year assignment of a small amount of Jackson Prairie storage through an asset management arrangement with Cabot Oil & Gas Marketing Corporation ("Cabot") that will reside in the power book, involving 6,704 MMBtu per day of deliverability and 140,622 MMBtu of storage capacity. This assignment provides the power portfolio with access to natural gas storage, which is instrumental for intraday balancing of load, integration of renewable resources, and meeting peak-day load requirements with gas-fired generation resources throughout the year.[157] Contrary to the Joint Parties' claims, the opportunity to purchase the gas at low summer prices and store the gas to sell during the higher priced winter months does not exist as the Cabot asset management agreement is for year-round reliability and renewable

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[156] *See* Mills Exh. No. DEM-12CT 11-13, 54:7-55:2.
[157] *See* Mills Exh. No. DEM-12CT 23:12-15.

resource integration management.[158] PSE's rate year power costs, accordingly, should not include any benefit for the seasonal gas price differences.

d. Regional Load Adjustment

80. The Joint Parties reduced the AURORA model's regional loads in the Pacific Northwest, the load of Southern California Edison, and the load of Pacific Gas and Electric Company by assuming no load growth for 2009, 2010, and 2011 in the AURORA input database. Although PSE does not agree with the ad hoc methodology[159] used by the Joint Parties in deriving their proposed regional load reduction, PSE agrees that the same economic trend data that reduced PSE's load forecast may have an impact on the regional load forecast. PSE adopts the $1.1 million reduction of rate year power costs proposed by the Joint Parties; however, this should be a one-time "Not In Model" power cost adjustment and not an AURORA model adjustment as the Joint Parties have proposed.[160]

e. Westcoast Pipeline Basis Benefit

81. PSE acquired Westcoast Energy T-South capacity in order to improve the reliability and predictability of gas supply to its generation portfolio, by diversifying supply risks.[161] When setting rates, PSE bases projected rate year gas prices on a forecast of what is expected to occur in the rate year, as represented by a three-month average forward monthly gas price forecast. In this instance, the gas is sourced at the Station 2 hub, which is not a liquid trading hub and does not have a transparent forward price curve. Therefore, to determine the forecast gas price at the Station 2 hub, PSE obtained several broker quotes of the basis differential between the Station 2

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[158] *See* Mills, Exh. No. DEM-12CT 25:16-21.
[159] The Joint Parties simply picked loads they believed "represent a significant portion of WECC loads", and input them into AURORA. *See* Joint Testimony, Exh. No. 1TC 7:14-21: *see also* Joint Parties, Exh. No. JT-2.
[160] *See* Mills Exh. DEM-12CT 28:4-7.
[161] *See* Riding, Exh. No. RCR-6T 7:17-19.

hub and the Sumas hub for the rate year. There are no instances where the calculated basis gain is more than the cost of the pipeline capacity based on the additional broker quotes obtained.[162] However, PSE is willing to accept the risk that pricing benefits will offset the pipeline costs, and proposes that the Westcoast pipeline capacity rate year power costs be offset 100% with a forecast benefit of the basis differential between the Station 2 and the Sumas hub.[163]

82. The Commission should reject the Joint Parties' calculation that would use historical prices to determine the rate year benefit of the Westcoast pipeline capacity acquisition.[164] The Joint Parties use the actual daily basis differential between the two hubs (Station 2 hub versus Sumas hub) from calendar year 2008 as a proxy for the rate year basis differential and propose a total benefit of nearly $10.0 million, or $1.7 million *more* than the cost of the pipeline capacity.[165]

f. Projected Production Operations and Maintenance Costs

1. Baker and Snoqualmie

83. PSE's pro forma adjustments for the Baker and Snoqualmie hydroelectric plants are for rate year fixed payments and expenses mandated by the respective FERC licenses. If PSE did not make these payments, PSE would be in violation of the respective licenses, subject to the enforcement provisions of the Federal Power Act, and in breach of the settlement agreement for the Baker License.[166] Kim Lane provided testimony on the fixed fee payments and budgeted costs of the tasks required by the license.[167] The Commission has previously allowed cost

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[162] *See* Mills Exh. No. DEM-12CT 34:1-9.
[163] *See* Mills Exh. No. DEM-12CT 31:10-12.
[164] See Riding Exh. No. RCR 6T-10:1-21.
[165] *See* Joint Parties, Exh. No. JT-1CT 16:9-19:11.
[166] *See* Lane, Exh. No. KWL-1T 10:3-11.
[167] *See* Lane, Exh. No. KWL-1T 7:9-15; *see also* Lane, Exh. No. KWL-1T 14:10-15:2; *see also* Lane, Exh. No. KWL-3.

estimates for work required as a result of a governmental ruling,[168] and likewise should allow these payments for obligations that PSE is required by law to perform.

84. In Commission Staff's response to Bench Request No. 3, submitted after the hearings, Commission Staff appears to accept the fixed payment obligations included in the Baker License of $1,822,170 as an appropriate pro forma adjustment. The Snoqualmie License fixed payment obligations are also proper and should be included in the power cost adjustment. Moreover, as discussed above, one cannot turn a blind eye to the other required obligations that must be carried out during the rate year for both the Baker and Snoqualmie licenses.

2. Colstrip Operations and Maintenance Costs

85. Commission Staff proposal to use a historical five-year average and Public Counsel proposes to use test year actual costs for determining Colstrip operations and maintenance costs. Both of these proposals result in projections that ignore the effects of technology changes, changes in maintenance cycles, changes in regulatory requirements and changes in costs for labor, materials and contracts.

86. As Mr. Jones testified, use of historical costs excludes known and measurable wage and benefit increases, known and measurable increases in costs related to pollution control measures, known costs related to strike contingencies, and other maintenance costs that are the same as those that this Commission has approved in past rate proceedings.[169] The Company's proposed rate year costs were provided by the plant owner, PPL-Montana, and have been both reviewed by each Colstrip owner and approved by a majority of owners. PSE used the same methodology to project rate year maintenance in the last six rate proceedings, and the Commission has

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[168] *See Wash. Utils. & Transp. Comm'n v. Wash Natural Gas*, 23 P.U.R.4th 184, 194, Docket No. U-77-47 (1977).
[169] *See* Jones, Exh. No. MLJ-5CT 3:19-4:7 *see also* Jones, Exh. No. MLJ-7:4-10.

approved such methodology.[170] PSE's methodology has been more accurate over the past years than the proposed use of historical data.[171] The Commission should approve PSE's methodology for determining Colstrip production operations and maintenance costs as it is clearly a better calculation of the costs expected to be incurred during the rate year.

3. Maintenance Costs For Natural Gas and Wind Turbines

a. Major maintenance

87. The Commission should approve the projected costs for major maintenance proposed in PSE's rebuttal testimony.[172] PSE agrees with the methodology for calculating the major maintenance costs recommended by Commission Staff and Public Counsel, but requests Commission clarification that rate recovery for actual major maintenance costs for turbines with or without maintenance contracts[173] be capitalized and amortized to expense over the estimated period until the next planned major maintenance activity.

b. Other maintenance expense

88. The Commission should approve the projected operations and maintenance expense for other maintenance proposed in PSE's rebuttal testimony,[174] which are summarized below:

89. PSE's proposal to use the test year maintenance costs for Goldendale Generating Station ("Goldendale") is preferable to Commission Staff's proposal to use an annualized thirty-month average of Goldendale actual maintenance expenses. Commission Staff includes data from the period when Goldendale was transitioning owners, which is not reflective of current expenses.

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[170] *See* Jones, Exh. No. MLJ-5CT 3:5-13.
[171] *See* Jones, Exh No. MLJ-6; *see also* Jones, Exh. No. MLJ-7.
[172] *See generally* Odom, Exh. No. LEO-13CT; s*ee also* Story, Exh. No. JHS-14T.
[173] *See* Odom, Exh. No. LEO-16.
[174] *See generally* Odom, Exh. No. LEO-13CT; s*ee also* Story, Exh. No. JHS-14T.

Goldendale's actual test year expenses more accurately reflect the operating conditions of the turbines in relationship to PSE's resource portfolio.[175]

90. PSE proposes to use Goldendale data as a proxy for Mint Farm as Mint Farm was not in service during the test year. Mint Farm is a generation facility of similar design as Goldendale.[176] Commission Staff's proposal uses expenses from Mint Farm, but only for January to August 2009. Commission Staff proposes to use a seven-month time period that excludes important fall and winter data and does not reflect normal operations at Mint Farm. The more appropriate method is to use a full year of cost information from a like facility, such as Goldendale.[177]

91. The time period Commission Staff proposes to use for determining maintenance on the Sumas Generating Station is similarly inappropriate. Commission Staff proposes to use August 2008 through August 2009 data, but Sumas was acquired during 2008 and was not fully staffed in August 2008. Accordingly, PSE's proposal to use Sumas actual expenses for the twelve-month period ending October 2009 results in the most complete and accurate projection of costs.

92. Commission Staff's proposal to use a five-year historical average of maintenance costs for Whitehorn, Fredonia, Frederickson and Encogen should be rejected as such data deflates costs for labor, chemicals, and material. These costs have all steadily increased over the five-year period.[178] PSE's proposal to use test year data excludes old data and results in projections that reflect current operations and maintenance practice.[179]

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[175] *See* Odom, Exh. No. LEO-13CT 8:2-7.
[176] *See* Odom, Exh. No. LEO-13CT 8:9-9:9; s*ee also* Henderson, Exh. No. JMH-4.
[177] *See* Odom, Exh. No. LEO-13CT 8:9 – 9:9.
[178] *See* Odom, Exh. No. LEO-13CT 10:13-14.
[179] *See* Odom, Exh. No. LEO-13CT 10:11-13.

93. The Commission should reject Commission Staff's proposal to remove production operations and maintenance costs from the Wild Horse, Hopkins Ridge, and Hopkins Ridge Infill Projects related to contract escalation and fee adjustments in the executed agreement. Escalation costs are increases in maintenance costs tied to the Consumer Price Index-Urban in the case of Hopkins Ridge and the Gross Domestic Product Implicit Price Deflator, for Wild Horse. This industry standard escalation fee is predictable and based on at least four years of inflation data, including 2010.[180] The Commission has approved this type of adjustment in past proceedings.[181]

94. Additionally, PSE will experience a significant increase in contractual maintenance costs for Hopkins Ridge beginning December 2010, when that facility's initial five year old service agreement expires, and Vestas will not continue maintenance of the Hopkins Ridge turbines. Because PSE recently completed negotiations for a similar service maintenance agreement for its Wild Horse expansion, it has appropriately applied this pricing information to Hopkins Ridge for the last four months of the rate year.[182]

95. Commission Staff claims that backfeed power costs and production royalty payments for the Hopkins Ridge Infill and Wild Horse Expansion projects are not known and measurable. In fact these are known and measurable contract obligations that PSE will incur as a result of expanding its wind production; they are not speculative or optional[183] and should therefore be allowed for rate recovery.

96. Finally, the Commission should accept PSE's production operations and maintenance costs for infrastructure maintenance at Hopkins Ridge and Wild Horse. Expenses to maintain the

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[180] *See* Odom, Exh. No. LEO-13CT 16:6-25:18.
[181] *See, e.g., Wash. Utils. & Transp. Comm'n v. Avista Corp.* Order 12, Docket No. UE-991606 & UG-991607 at ¶ 227 (Sept. 29, 2000) (approving recovery of fees for maintaining a loan account, although the amount may vary slightly with the amount borrowed).
[182] *See* Odom, Exh. No. LEO-13CT 18:18-22.
[183] *See* Odom, Exh. No. LEO-13CT 20-21.

basic infrastructure of the Company's facilities through activities such as fire prevention and storm water management are certain to be incurred, and PSE's experience in managing its facilities provides the best operational knowledge of such costs.[184]

3. Hopkins Ridge Infill (Adjustment 10.06)

97. PSE appropriately includes a pro forma adjustment for the Hopkins Ridge Infill Project, which came into service during the test year. PSE's pro forma adjustment is consistent with the treatment of the new plant in the Company's 2007 general rate case, where the full value of the new plant was included in the revenue deficiency as a pro forma adjustment.[185] The Company includes in this adjustment the property taxes associated with this project as it is undisputed that PSE will owe property taxes on this new plant.

98. Commission Staff improperly adjusts property taxes to the 2008 property taxes payable in 2009. PSE's property tax amounts are calculated properly as explained below.

4. Wild Horse Expansion Project (Adjustment 10.07)

99. PSE placed the Wild Horse Expansion Project in service on November 9, 2009. This pro forma adjustment follows the same methodology that has been used in prior cases to determine rate year costs associated with new plant. In the Company's prefiled direct testimony and exhibits, the dollar amounts used in the cost analysis of the plant were used to estimate the impact of the plant on rate year costs. The Company updated these costs in its rebuttal filing to reflect lower estimates for the final costs of construction and rate year expenses.[186] The Company used the total capital cost expected to close to plant by December 2009 as supported by Mr. Roger Garratt to calculate the gross plant values for the Wild Horse Expansion.

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[184] *See* Odom, Exh. No. LEO-13CT 21:9-20.
[185] *See* Story, Exh. No. JHS-14T 27:18 – 28:1.
[186] *See* Story, Exh. No. JHS-14T 30:2-8.

100. There are several errors in Commission Staff's adjustment. First, Commission Staff uses actual construction work in progress balances through September 2009 to calculate gross plant values, which understates the final investment in the plant.[187] Second, as discussed above, Commission Staff fails to properly account for operations and maintenance expenses. Third, Commission Staff fails to provide for any property taxes for the Wild Horse Expansion Project. Other minor differences exist between PSE and Commission Staff which are the result of differences in the formula used to calculate depreciation expense for November and December 2009.[188] The Commission should accept PSE's calculation for this adjustment.

5. Mint Farm (Adjustment 10.08)

101. PSE acquired Mint Farm and placed it in service in December, 2008. PSE's pro forma adjustment follows the same methodology used in prior cases to determine the rate year costs associated with plant put in service during the test year. In its direct case, PSE used the dollar amounts in the cost analysis of the plant to estimate the impact of the plant on rate year costs. At rebuttal the Company updated these costs to reflect actual plant balances through October, 2009 and trued up the estimates of the final costs of construction and rate year expenses.[189]

102. Commission Staff calculated the Mint Farm plant balances and depreciation and amortization based on actual plant additions through August 2009. The flaws associated with the Staff's operating and maintenance expense this calculation are discussed above. Commission

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[187] *See* Story, Exh. No. JHS-14T 31:8-9.
[188] In its rebuttal filing, PSE reclassified additional point-to-point, scheduled and reactive costs on a BPA transmission contract that were deemed to be allocable to Wild Horse Expansion. This change merely represented a reclassification from the main power cost adjustment to the Wild Horse Expansion adjustment. The fact that PSE and Commission Staff present different amounts on this adjustment does not signify an overall difference when transmission costs are viewed in total.
[189] *See* Story, Exh. No. JHS-14T 32:18-33:6.

Staff's adjustment provides no property taxes for Mint Farm.[190] The Commission should accept PSE's calculation for this adjustment

6. Sumas (Adjustment 10.09)

103. Sumas was placed in-service during the test year. PSE's pro forma adjustment follows the same procedures used in past cases for generating plant approved for recovery in a prior docket.[191] Property taxes for Sumas were updated to the current estimate. Commission Staff adjusts property taxes to 2008 property taxes payable in 2009.[192] The Commission should accept PSE's calculation for this adjustment.

7. Whitehorn (Adjustment 10.10)

104. Whitehorn was placed in service during the test year and like Sumas is pro formed into the test year using the methodology the Commission has historically accepted.[193] The calculation and treatment of restated property taxes that Commission Staff proposes for this adjustment are consistent with that described in the Hopkins Ridge Infill and Sumas plant adjustments and should be rejected for the same reasons.

8. Baker Hydro Relicensing (Adjustment 10.11)

105. The Baker Project is subject to FERC annual charges for use of federal lands.[194] The fee for 2010 is known and measurable—it will be $1,109,030.00.[195] Commission Staff wrongly

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[190] Fuel costs presented on this adjustment differ between PSE and Commission Staff for the reasons discussed above starting in paragraph 98. The difference in rate base between PSE and Public Counsel is due to updates in PSE's rebuttal filing and reflected in PSE's Response to Bench Request No. 3, Exh. No. B-3, that were not adopted by Public Counsel, but presumably are uncontested by Public Counsel.

[191] In PSE's 2007 general rate case, the full value of the new plant was included in the revenue deficiency as a pro forma adjustment for the period of time it was in-service. *See* Story Exh. JHS-14T at 35:5-12; *see also Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 12, Docket No. UE-072300 *et al.* (Oct. 8, 2008)

[192] *See* Marcelia, Exh. No. MRM-5.

[193] In PSE's 2007 general rate case, the full value of the new plant was included in the revenue deficiency as a pro forma adjustment for the period of time it was in-service. *See* Story, Exh. No. JHS 14T 37:8-15; *see also Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 12, Docket No. UE-072300 *et al.* (Oct. 8, 2008).

[194] *See* Lane, Exh. No. KWL-1T 8:9-10.

concludes that PSE will only be required to pay 75% of the fee. As Mr. Lane testified, due to a phase-in of the initial implementation of the Per Acre Rent Schedule, the Bureau of Land Management reduced the 2009 per acre rent by 25 percent.[196] However, "[i]n calendar year 2009, all holders will pay 75 percent of the scheduled rental rates, and thereafter, 100 percent of the scheduled rental rates."[197]

9. Miscellaneous Operating Expense (Adjustments 9.09 and 10.14)

106. The Commission should reject Public Counsel's proposal to remove the increases to Potelco/Quanta service provider transmission and distribution contracts.[198] All contractual terms are final with unit pricing information and amendments to the contract with Potelco/Quanta having been fully executed in December 2009.[199] PSE's pro forma adjustment understates the final agreed upon unit pricing and will need to be absorbed by PSE due to regulatory lag.[200]

10. Property Taxes (Adjustments 9.10 and 10.15))

107. PSE calculated its rate year property taxes in the same manner as in past cases. Mr. Marcelia testified to the 13-14 month process for determining actual property taxes.[201] There are three components that PSE needs each year in order to calculate its property tax—the electric and gas property values, the system ratios for electric and gas operations,[202] and the levy rates.

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[195] *See* Lane, Exh. No. KWL-1T 9:6.
[196] *See* Lane Exh. No. KWL-1T 8:1-9:21.
[197] *See* Lane, Exh. No. KWL-1T 9:8-15 (citing Federal Register / Vol. 73, No. 212 / Friday, October 31, 2008 / Rules and Regulations, 43 CFR Parts 2800, 2880, and 2920, *Update of Linear Right-of-Way Schedule; Final Rule*). Additionally, the difference in rate base between PSE and Public Counsel is due to changes made by PSE subsequent to hearings and as reflected in PSE's Response to Bench Request No. 3 that were not adopted by Public Counsel. Amounts used by PSE should be approved and are presumably uncontested by Public Counsel.
[198] Although Commission Staff initially removed the increases reflected in the test year, Commission Staff's Response to Bench Request No. 3, Exh. No. B-3, submitted after the hearings, indicates that Commission Staff now accepts PSE's adjustment.
[199] *See* Valdman, TR. 173:12-20.
[200] *See* Valdman, Exh. No. BAV-10CT 15:19-21.
[201] *See* Marcelia, Exh. No. MRM-4T 6:6-7; *see also* Marcelia, Exh. No. MRM-5.
[202] The counties use the actual system ratio to equalize the Company's values with the values of other taxpayers in that county. *See* Marcelia, Exh. No. MRM-4T 7:16-8:4.

For financial reporting purposes, each of these events obligates the Company to update its calculations, and PSE used these same updated calculations for regulatory purposes just as it has done in past cases.[203] PSE updated the actual electric and gas property values for 2009, which became available in July 2009. Additionally, PSE updated the actual system ratios for electric and gas operations for 2009, which became available in December 2009. Because the levy rate—the third component for calculating property taxes—will not be available until March or April of 2010, PSE used the average of the levy rates for the past four years in its calculation, and Mr. Marcelia testified to the appropriateness of this methodology.[204]

108. Commission Staff originally used test year amounts, which are based on estimated values for all three components of the property tax calculation, for its estimate of restated property taxes. In its response to Bench Request 3, Commission Staff continues to use 2008 property taxes, but updates the calculation for the actual 2008 values for each component of the calculation. Therefore, Commission Staff continues to use stale 2008 data in calculating property tax. Despite the fact that two of the three factors in determining the property tax for the rate year are now available, Commission Staff ignores these known and measurable factors and instead uses the property taxes for 2008 as an estimate for rate year property taxes.[205] In so doing, Commission Staff's adjustment excludes all plant acquired or put into service after January 1, 2008,[206] even though PSE will pay property taxes on this plant during the rate year.[207]

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[203] *See* Marcelia, Exh. No. MRM-4T 9:3; *see generally*, Marcelia, Exh. No. MRM-4T 8:13 – 10:8.
[204] *See* Marcelia, Exh. No. MRM-4T 15:3-16:13; *see also* Marcelia, Exh. No. MRM-6.
[205] *See* Marcelia, TR. 519:20-520:21.
[206] *See* Marcelia, TR. 520:4-11.
[207] Moreover, by lumping property taxes together in one adjustment, rather than showing property taxes on the adjustment for each plant, Commission Staff's presentation of property tax disguises the fact that it is excluding property taxes for plant in service in 2009.

11. Director and Officers Insurance (Adjustments 9.12 and 10.17)

109. Directors and Officers ("D&O") Insurance is a necessary cost of doing business, and the majority of the risk that D&O insurance addresses is derived from operations of the Company. The Company's calculation allocates a portion of this insurance to subsidiaries and accomplishes the sharing of risk and cost that the Commission has previously approved.[208] The 50% allocation of premiums to shareholders proposed by Commission Staff and Public Counsel has no foundation and is inconsistent with the Commission's established treatment of such costs.

12. Property and Liability Insurance (Adjustments 9.16 and 10.23)

110. PSE and Commission Staff agree on this known and measurable adjustment, which uses the actual premiums for property and liability insurance for the rate year. Public Counsel ignores these known and measurable premiums and instead uses the test year premiums, based on the unsupported suggestion that there may be hypothetical but unidentified offsets to the actual, known cost of these insurance premiums. Public Counsel's approach should be rejected.

13. Pension Plan (Adjustments 9.17 and 10.24)

111. PSE's retirement plans are an essential element of PSE's total compensation, recruiting and retention programs for all employees.[209] Nevertheless Public Counsel and FEA propose to arbitrarily adjust PSE's retirement programs for ratemaking purposes. FEA asserts that PSE should solely utilize a defined contribution plan. As discussed by Mr. Hunt, "the utility industry continues to offer both defined benefit and defined contribution plans".[210] Therefore, to be market competitive, PSE currently maintains both plans. Moreover, changes to such benefit

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[208] *See* Stranik, Exh. No. MJS-12T 21:1-11.
[209] *See* Hunt, Exh. No. TMH-9CT 2:11-12.
[210] Hunt, TR. at 448:11-13; *see also* Hunt, Exh. No. TMH-10.

plans that other companies have recently made—for example, changing to a cash balance formula—were already made by PSE several years ago.[211]

112. PSE's funding of its pension plan is proper and consistent with its fiduciary and legal obligations. Due to dramatic stock market turmoil, PSE's retirement plan sustained significant losses during 2008.[212] In light of these losses, PSE formalized a pension funding policy with the goal of establishing a "reasonable and consistent pattern of employer contribution."[213] Consistent with the Company's funding policy and with the Pension Protection Act, PSE contributed to the plan in 2009.[214] Public Counsel and FEA argue that the 2009 funding amount should be removed because, among other things, the amount of contribution is subject to discretion by PSE's management.[215] The fact that PSE's management has some amount of discretion in the funding of the pension plan is not a sound basis for rejecting the actual funding amounts made by the Company. PSE's contributions "have been reasonable and consistent with the Company's stated goals of returning the plan to a fully funded level with a reserve in case of volatility."[216] PSE did not make contributions in 1999-2002 and 2004-2005 because of plan funding levels. In 2006 and 2007, PSE could have made tax deductible contributions; however the Company chose not to because the plan was fully funded.[217] The 2008 and 2009 contributions were both conservative compared to the maximum allowed contributions, and 2009 contribution was at the low end of the guideline range established for contribution.[218]

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[211] *See* Hunt Exh.No. TMH-9CT 4:18-22.
[212] *See* Hunt, Exh. No. TMH-9CT 9:16-17.
[213] Hunt, Exh. No. TMH-13C; *see also* Hunt, TR. 452:11-20.
[214] *See* Hunt, Exh. No. TMH-9CT 9:6-15.
[215] *See* Smith, Exh. No. RCS-1TC 16.
[216] Hunt, Exh. No. TMH-9CT 12:5-7.
[217] *See* Hunt, Exh. No. TMH-9CT 12:7-10.
[218] *See* Hunt, Exh. No. TMH-9CT 12:10-19.

113. FEA's proposal to retreat from long-established Commission practice of using actual cash payments to determine rate recovery should be denied. Although actual cash payments or SFAS 87 calculated expense equal each other over time and either could be used to fix pension expense for ratemaking purposes, it is improper and unfair rate making policy to move back and forth between these two methodologies, electing whichever methodology provides the lower contribution recovery at any given time. Such an ad hoc approach is not reasonable and guarantees the Company will under-recover pension costs over time.

114. Likewise, Public Counsel's and FEA's recommendations to remove all Supplemental Executive Retirement Plan ("SERP") expense from PSE's revenue requirements should be rejected. SERP is part of the total compensation package for executives at PSE and needs to be viewed in context of the overall package, not in isolation.[219] The Company's SERP allows executives to replace income at the same proportions in retirement as compared to other employees and allows mid-career employees to come to PSE without suffering a decrease to their retirement benefits.[220] It complies with IRS rules for "non-qualified" plans, including IRS Section 409A.[221] Public Counsel's and FEA's claim that other jurisdictions have not allowed SERP expenses in revenue requirements is irrelevant and without merit. This Commission has historically allowed SERP expenses in revenue requirements and has stated: "The ultimate issue is whether total compensation is reasonable and provides benefits to ratepayers, not whether incentive compensation is pay in stock or whether compensation, particularly for executives, is similar to that of other comparable companies."[222] The Company's SERP meets this test. Taken

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[219] *See* Hunt, Exh. No. TMH-9CT 22:1-14.
[220] *See* Hunt, Exh. No. TMH-9CT 18:18-19:2. As of November 30, 2009, seven of PSE's 12 officers can be considered mid-career transferees. *See* Hunt, Exh. No. TMH-9CT 19:5-6.
[221] *See* Hunt, Exh. No. TMH-9CT 20:3-5.
[222] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc*, Order 04 at ¶ 128 (April 17, 2006).

as part of the overall compensation package, it is reasonable as a common feature of a market competitive pay program in the utility industry.[223] It provides benefits for PSE's customers by attracting and retaining competent and skilled executives.[224]

14. Wage Increase (Adjustments 9.18 and 10.25)

115. The wage increases PSE includes in this case are known and measurable and should be approved by the Commission. For IBEW union employees, the Company contractually committed to an increase of 3.25% on April 1, 2009 and an increase of 3% on January 1, 2010.[225] These increases are "market competitive and reasonably sized to preserve PSE's competitive pay position."[226] With regard to non-union employees, the Company's Board approved merit increases of three percent and PSE is now in the process of allocating those monies to managers who will be determining individual merit-based increases for their employees. Those increases will be paid in March 2010.[227]

116. Public Counsel removes the IBEW wage increase in January 2010 and the non-union wage increase in March 2010 from rate recovery due to the current state of the economy[228] Commission Staff removes the non-union wage increase in March 2010 claiming it is not known and measurable. The adjustments of Public Counsel and Commission Staff should be rejected. First, as discussed above, the wage increases included in PSE's case are all known and measurable. Second, PSE has modified its compensation program as a result of the economic downturn by freezing officer pay at 2009 levels,[229] which is reflected in the Company's

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[223] *See* Hunt, Exh. No. TMH-9CT 18:6-21; 22:17-23:10; *see also* Hunt, Exh. No. TMH-17C 8.
[224] *See* Hunt, Exh. No. TMH-1T 17:16-18:6.
[225] *See* Hunt, Exh. No. TMH-9CT 25:4-6; *see also See* Hunt, Exh. No. TMH-1T 5:9-18.
[226] Hunt, Exh. TMH-9CT 25:11-13.
[227] *See* Hunt, TR. 449:24-450:6.
[228] *See* Parvinen, Exh. No. MPP-1T 7:507.
[229] *See* Valdman Exh. No. BAV-3; *see also* Valdman Exh. No. BAV-10 CT 11:8-9.

adjustment. Third, the utility industry "continues to face labor and managerial shortages" and PSE must remain market competitive with salaries in order to acquire and retain qualified employees.[230] Fourth, increased productivity does not translate into "offsets" or reduced hours worked as Commission Staff and Public Counsel claim. Instead, PSE is able to reallocate employees to meet due to new demands such as those placed on the Company by "increased regulations, compliance, and the ongoing work of system replacement."[231]

15. Employee Insurance (Adjustments 9.20 and 10.27)

117. PSE's updated adjustment for employee insurance should be accepted by the Commission. PSE updated this adjustment on rebuttal to reflect (1) the proper employee count and (2) the contractual 2010 increase in the flex credit of 4.75%.[232] In contrast, Commission Staff's adjustment fails to include the proper employee counts, and Public Counsel's adjustment ignores the contractually agreed upon 2010 flex credit increase of 4.75%. Contrary to Public Counsel's unsupported assertion, no offsets in terms of efficiency gains have been identified associated with the flex credit cost increase.[233]

16. Regulatory Assets and Liabilities (Adjustment 10.31)

118. PSE included as a decrease to rate base the $25 million received from Cascade Water Alliance as consideration for the sale of White River assets. Commission Staff and Public Counsel included the $25 million plus an <u>estimated</u> $2.1 million tax loss resulting in a $27.1 million decrease in rate base. Both Commission Staff and Public Counsel inappropriately reduce

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[230] Hunt Exh. No. TMH-1T 6:3-12.
[231] Hunt Exh. No. TMH-9CT 26:13-15.*see also* Valdman, TR. 191:5-7.
[232] *See* Stranik, Exh. No. MJS-12T 27:15-28:3. The original employee counts included in this adjustment were based on a system report that was run at the start of each month in 2008 for employees who were active and enrolled in a medical coverage choice at the date the report was run. As a consequence of new employees having 30 days to sign up for coverage, new employees electing coverage any time after the beginning of the month were not included in the employee count for that month. These updates were provided to all parties in August 2009.
[233] *See* Stranik, Exh. No. MJS-12T 28:10-16.

rate base for the $2.1 million loss since both parties ignore the offsetting balance sheet effect of adding an asset for the tax receivable. Mr. Marcelia further explains why this tax-related adjustment is not appropriate and should be rejected by the Commission.[234] PSE will not know the full tax impact of the transaction until all the Whiter River transactions have been completed. As stated in the Commission's order in Docket UE-090399, the Company will bring the application of proceeds from the sale and disposition of all project proceeds including sales of surplus property for Commission consideration in the Company's next general rate case after the sale of all project assets is complete.[235]

119. PSE included in rate base $5.8 million during the rate year which represents the $10.4 million Colstrip settlement payment less the $2.0 million insurance receivable along with carrying charges to be recovered over five years at $1,967,556 per year.[236] Commission Staff included the total net Colstrip settlement payment of $8.4 million as part of production operations and maintenance in power costs. Public Counsel removes the total Colstrip settlement payment as a non-recurring or at least infrequently occurring event. Public Counsel fails to take into consideration this settlement payment protects the customers' interest in a low cost production resource and is known and measurable. PSE's methodology of treating this cost is the appropriate method to adopt for rate recovery.

17. Fredonia (Adjustment 10.33)

120. Commission Staff accepts the inclusion of the Fredonia purchase in its response to Bench Request No. 3. Commission Staff's method of calculating property taxes is the same as

[234] *See* Marcelia, Exh. No. MRM-4T 2:17 – 3:20.
[235] *See In the Matter of the App. of Puget Sound Energy, Inc. for an Order Authorizing the Transfer of White River Assets*, Order 01 at ¶ 13, Docket UE-090399 (May 14, 2009).
[236] *See* Exh. No. B-3; PSE's Response to Bench Request No. 3, Adjustment 10.31.

described in the Hopkins Ridge Infill and Sumas plant adjustments and should be rejected for the same reasons previously discussed.

18. Mint Farm Deferral (Adjustment 10.34)

121. Pursuant to RCW 80.80.060(6) PSE proposes to defer over a 10 year period the PCA-defined fixed and variable costs associated with the acquisition of Mint Farm, and interest on the deferral.[237] The statute broadly allows deferral of costs incurred in connection with investment in baseload electric generation such as Mint Farm.[238] The deferral is intended to encourage regulatory certainty and investments in clean, reliable, cost-effective electricity.[239]

122. In its response to Bench Request No. 3, Commission Staff updated its Mint Farm deferral. The Company agrees with the Commission Staff that the net variable costs through November 2009 for the Mint Farm Deferral should be included in the adjustment, but as PSE has testified, the total deferral should be amortized over ten years and PSE should be allowed to recover the interest incurred on the deferral. The Company has adjusted Commission Staff's workpapers from the Bench Request 3 response to include interest on the total net fixed and variable deferred amounts for Mint Farm, see page 3, lines 6 and 15-17, of Appendix E. The total fixed and variable deferral, including interest, was then used to calculate the rate year rate base, accumulated amortization, deferred taxes and amortization expense using a ten year amortization period.[240] After making these changes Page 1 of Appendix E shows the Company's

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[237] *See* Story, Exh. No. JHS-14T 52:1-58:9.
[238] *See* RCW 80.80.060(6).
[239] RCW 80.80.005(1)(h) states as follows: " The state of Washington has an obligation to provide clear guidance for the procurement of baseload electric generation to alleviate regulatory uncertainty while addressing risks that can affect the ability of electric utilities to make necessary and timely investments to ensure an adequate, reliable, and cost-effective supply of electricity. *See also* RCW 80.80.005(4)(b) ("To the extent energy efficiency and renewable resources are unable to satisfy increasing energy and capacity needs, the state will rely on clean and efficient fossil fuel-fired generation and will encourage the development of cost-effective, highly efficient, and environmentally sound supply resources to provide reliability and consistency with the state's energy priorities.").
[240] *See* Appendix E, page 2, line labeled Mar-11.

proposed adjustment for the Mint Farm deferral. Adopting this adjustment lowers the Company's revenue deficiency by $2,181,212.

123. Commission Staff's proposed 15-year amortization period is excessive. PSE's proposed ten year amortization period for the Mint Farm deferral is consistent with recent decisions. For example, the cost of the Mint Farm deferral are approximately 70% of the storm costs that were deferred over ten years as approved in the settlement of PSE's 2007 general rate case.[241]

124. PSE should be allowed to recover carrying costs on the deferral. As Mr. Story testified:

> When a company does not have revenues coming in to recover its costs of purchasing a new plant that is in-service, it has to finance the funds to cover the lack of revenues. This is true not just for the cash expenditures that are funding interest on the financing used to buy the plant and fund its current operations and maintenance expenses, it is also true for depreciation and the equity return not received. Depreciation and the equity return are certainly the two main contributors of cash generation for a utility. Without this cash available, additional funds must be raised and the cost of financing these new funds are an additional cost associated with operating the plant that is now in-service. This is the interest that is being deferred and the cost is calculated using the rate the Commission has already approved as the appropriate cost of capital in the Company's last general rate case. There is no part of this that is "tantamount to double recovery" – it is simply recovery of all of the costs associated with the resource.[242]

125. Contrary to Commission Staff's assertions,[243] there is no need to use Schedule G from the PCA Settlement Stipulation when calculating a new resource deferral. The Company removes all costs associated with the new resource, substitutes in the costs for purchased power that were approved in the Company's last rate proceeding, and credits the deferral for these costs. This calculation is based on the run time of the machine multiplied by the costs of purchased power that were approved but no longer need to be purchased. This provides the customer the benefit

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[241] *See* Story, Exh. No. JHS-14T 54:18 – 55:1.
[242] Story, Exh. No. JHS-14T 53:4-17.
[243] *See* Martin, Exh. No. RCM-1T 23:1 – 24:21.

of an offset to the deferral for the costs already in rates and puts that cost back into power cost for PCA review. All costs that are associated with Mint Farm are removed from the Income Statement and the costs that were originally allowed for purchased power have been restored as if the machine were not available.[244] In contrast, Mr. Martin's proposal for deferral does create a duplication of costs for PSE.[245]

126. Public Counsel completely rejects the Company's Mint Farm deferral adjustment, based on its incorrect determination that Mint Farm was not prudently acquired. The fallacies of Public Counsel's analysis on Mint Farm prudence were identified above.

19. Net Interest on Simplified Service Cost Method (Adjustment 10.36)

127. The Commission should approve PSE's request for recovery of interest paid to the Internal Revenue Service ("IRS") relating to the simplified service cost method of accounting that provided significant benefits to customers. From 2001 to 2003, PSE used this methodology in its tax returns under section 263A of the Internal Revenue Code. This method resulted in tax deductions totaling $204 million, for a tax benefit of $71.4 million. After an IRS audit disallowed the tax deduction, PSE filed a formal protest. Ultimately, PSE succeeded in retaining approximately 85% of its original tax deductions in a settlement reached with the IRS. The settlement, however, required PSE to make an interest payment to the IRS.[246]

128. In PSE's 2004 general rate case, with the IRS review pending, PSE sought pre-approval of an adjustment to rates should the IRS disallow the methodology. The Commission denied PSE's request but instructed PSE to file an accounting petition seeking appropriate treatment of

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[244] *See* Story, Exh. No. JHS-14T 55:4-58:9.
[245] *See* Martin, Exh. No. RCM-1T 19. Mr. Martin would add to these calculated purchase costs, that are added back to the income statement, by also keeping the variable costs associated with the new machine in the income statement. As the Company has already reinstated the cost of the purchased power that would have been there if the machine was not available, this creates duplication of costs.
[246] *See* Marcelia, Exh. MRM-1T 11: 1-13:9; Exh. MRM-3.

back taxes and interest assessed in the event the IRS required PSE to pay back taxes and interest.[247]

129. Pursuant to the Commission directive, PSE filed an accounting petition in 2008, but this petition has not yet been brought before the Commission. Given that PSE attempted to prospectively remove the benefit of this deduction from rates in its 2004 general rate case filing, but instead was instructed by the Commission to do exactly as it has done, it is difficult to understand how PSE can now be faulted for "going back to prior test years" and seeking recovery of this interest that resulted from the use of the simplified service cost method.[248]

130. The disallowance of the simplified service cost method demonstrates that PSE's new accounting method for the tax treatment of repairs should not be pro formed into this case as FEA proposes. The IRS granted a limited approval for the Company to adopt the repairs methodology after the close of the test year. The methodology has not yet been audited by the IRS. Moreover, FEA's proposed adjustment is one sided in that the Company has incurred substantial capital expenditures since the close of the test year that are not included in this rate proceeding. Those capital expenditures, in part, are offset by the additional deferred tax. The additional deferred tax related to the method change is clearly offset and vastly overwhelmed by capital expenditures of nearly $700 million dollars since the close of the test year.[249]

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[247] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Order 06 at ¶¶ 156-159, Docket Nos. UG-040640 *et al*. (2005) (footnotes omitted and emphasis added).
[248] *See* Marcelia, TR. 507:8-25. Further, as Mr. Marcelia testified, it is important to distinguish interest owed the IRS from tax expense. *Id.* at 510:21-24. A conclusion that PSE should not be allowed to recover interest incurred as a byproduct of providing significant ratepayer benefits in the form of tax deductions, is flawed, based on the distinction between interest and tax obligations among other reasons.
[249] *See* Marcelia, Exh. No. MRM-4T 26:13-29:18.

20. Production Adjustment (Adjustment 10.37)

131. PSE's production adjustment is proper. The production factor is based on the ratio of the test period normalized delivered load to the rate year delivered load.[250] The production factor adjustment has been used to set rates since the mid-1970s.[251] This adjustment allows the Company a fair opportunity during the rate year to recover the rate year power and production costs that the Commission has approved during a particular proceeding. Because the same unit cost per kWh is built into rates for the rate year and the test year after the production factor has been applied, there is no positive or negative attrition built into the adjustment.[252]

21. Wild Horse Expansion Deferral (Adjustment 10.38)

132. The Wild Horse Expansion Project is a renewable resource whose costs are eligible for deferral under RCW 80.80.060. The methodology used to defer the costs associated with the Wild Horse Expansion Project is the same deferral methodology used in connection with the Mint Farm Energy Center. As discussed above, the Commission should allow deferral of carrying costs for the Wild Horse Expansion Project.

133. In its response to Bench Request No. 3, Commission Staff updated its adjustment for the Wild Horse Expansion Deferral. As with Mint Farm, the Company agrees with the Commission Staff's inclusion of the net variable costs through December 2009 for the Wild Horse Expansion Deferral and has adjusted the Commission Staff work papers in the same manner described above in the Mint Farm Deferral. *See* Appendix F at p. 3, lines 6 and 15-17. The total deferral, including interest, was then used to calculate the rate year rate base, accumulated amortization, deferred taxes and amortization expense using a two year amortization period. *Id.* p. 2, (lines

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[250] *See* Story, Exh. No. JHS-14T 14:3-8; *see also* Story, Exh. No. JHS-23.
[251] *See, e.g.*, *WUTC v. Wash. Nat. Gas*, Docket U-77-47 (1977): *see also* Story, Exh. No. JHS-14T 5:3-6:25.
[252] *See* Story, Exh. No. JHS-14T 16:3-9.

labeled Mar-11). After making these changes, page 1 of Appendix F shows the Company's proposed adjustment for the Wild Horse Expansion deferral.

22. Wild Horse Solar Demonstration Project (Adjustment 10.39)

134. PSE removed the Wild Horse solar demonstration project from its revenue requirement calculation. Although Roger Garratt discussed this small demonstration project in his testimony,[253] PSE did not seek a prudence determination for the project and thus it is appropriately excluded from recovery in this case.[254]

23. Aircraft Costs

135. The Commission should reject Public Counsel's proposal to remove from rate base and operating expense the costs associated with PSE's 1986 Beechcraft KingAir turboprop aircraft, and replace these costs with estimated alternative transportation costs. The costs of this airplane has been included in rates since it was purchased in 1986. The airplane provides value to the customers and the Company by allowing quick and safe access to the Company's generating resources in diverse and remote locations.[255] Public Counsel's purported calculation of the cost of alternative transportation fails to factor in such costs as the loss of productivity by employees having to drive long distances or wait for plane flights, or the additional delays that can result when relying on commercial airlines' flight schedules—particularly to the many remote, rural locations in which the Company now finds its operations. Additionally, Public Counsel ignores other benefits the airplane provides, such as performing snow level survey flights in the Cascades to allow for more efficient management of PSE's hydro operations.[256]

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[253] *See* Garratt, Exh. No. RG-1HCT 102:17 – 103:8.
[254] *See* PSE's Response to Bench Request No. 3, Exh. No. B-2; *see also* Stranik, TR. 600:9 – 602:21.
[255]*See* Stranik, Exh. No. MJS-12T 14:15-11.
[256] *See* Stranik, Exh. No. MJS-12T 15:13-18:16.

24. Normalize Injury and Damages Expense

136. Public Counsel's proposal to adjust the historical test year amount for Account 926, Injuries and Damages and replace it with a three-year average should be denied. Public Counsel has not demonstrated a reasoned basis for changing from the use of historical test year to a three-year average. To selectively average accounts over a specified period when they are higher than average, while using actual account balances for the test year when they are lower than average, would be arbitrary and unreasonable.

25. Equity Return On Mint Farm Energy Center

137. As previously discussed, the Commission should reject Public Counsel's adjustment to eliminate the equity return on the Mint Farm Energy Center.

C. Uncontested Restating and Pro Forma Adjustments

138. Appendix B lists the uncontested electric adjustments and associated differences in NOI and rate base. The Commission should adopt each of these uncontested electric adjustments.

D. Summary of Electric Revenue Requirements

139. Table 4 below summarizes the results of the electric retail revenue requirement deficiency of $110,303,620 proposed by PSE in this proceeding.

TABLE 4
Electric Revenue Requirement

	Rate Base	$3,805,678,581
×	Rate of Return	8.50%
	Operating Income Requirement	$ 323,482,679
–	Pro Forma Operating Income	$ 254,816,793
	Operating Income Deficiency	$ 68,665,887
÷	Conversion Factor	0.6212620
	Revenue Requirement Deficiency	$ 110,526,455
–	Large Firm Wholesale	$164,044
–	Sales from Resale-Firm	$58,791
	Revenue Requirement Deficiency	**$110,303,620**

E. Contested Natural Gas Restating and Pro Forma Adjustments

140. Appendix C presents the contested natural gas restating and pro forma adjustments (and their impact on NOI or rate base). The contested natural gas restating and pro forma adjustments not previously discussed in the electric adjustment, are discussed below.

1. Jackson Prairie (Adjustment 9.24)

141. PSE received a refund of tax and interest previously paid to the Washington State Department of Revenue relating to the expansion of the Jackson Prairie facility. PSE accounted for the refund in the same manner in which the original assessment was handled, with the sales tax portion of the refund being applied to capital orders associated with the Jackson Prairie project and the interest portion being applied to interest.[257]

F. Uncontested Natural Gas Restating and Pro Forma Adjustments

142. Appendix D presents the uncontested natural gas restating and pro forma adjustments (and their impact on NOI or rate base). The Commission should adopt each of these uncontested natural gas restating and pro forma adjustments.

G. Summary of Natural Gas Revenue Requirements

143. Table 5 below summarizes the results of the gas revenue requirement deficiency of $28,464,116 proposed by PSE in this proceeding.

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[257] *See* Marcelia, Exh. No. MRM-4T.

TABLE 5
Gas Revenue Requirement

	Rate Base	$1,469,293,922
×	Rate of Return	8.50%
	Operating Income Requirement	$124,889,983
–	Pro Forma Operating Income	$107,188,406
	Operating Income Deficiency	$17,701,577
÷	Conversion Factor	0.6218910
	Revenue Requirement Deficiency	**$28,464,116**

VIII. RATE SPREAD AND RATE DESIGN SETTLEMENTS

A. Electric Rate Spread and Rate Design Settlement

144. PSE requests that the Commission approve the Multiparty Settlement Re: Electric Rate Spread and Rate Design, which was filed with the Commission on January 15, 2010.

B. Natural Gas Rate Spread and Rate Design Settlement

145. PSE requests that the Commission approve the Multiparty Settlement Re: Natural Gas Rate Spread and Rate Design, which was filed with the Commission on January 15, 2010.

IX. LOW INCOME FUNDING

146. The Company proposed to increase the annual level of low-income electric and natural gas bill assistance funding by the corresponding percent increases to the residential class that are approved by this Commission. The amount of this percentage increase would be added to the low income tariff in the next program year.[258] No party opposed this increase to low income funding, and PSE respectfully requests that the Commission grant the requested increase.

[258] *See* Markell, Exh. No. EMM-1TC 38:9-11.

X. CONCLUSION

147. For the reasons set forth above and in the evidence that is before the Commission, PSE respectfully requests that the Commission issue an order approving its requested relief.

DATED this 19th day of February, 2010.

Respectfully submitted

PERKINS COIE LLP

By ______________________________
Sheree Strom Carson, WSBA # 25349
Jason Kuzma, WSBA #31830
Attorneys for Puget Sound Energy, Inc.

APPENDIX A

The table below presents the contested electric restating and pro forma adjustments and their impact on NOI or rate base

Contested Restating and Pro Forma Adjustments – Electric

Adjustment	NOI	Rate Base
Revenue and Expense	$80,396,404	
Power Cost Adjustment	$50,909,893	
Hopkins Ridge Infill	($187,340)	$4,075,268
Wild Horse Expansion Project	($4,929,041)	$70,953,078
Mint Farm	($51,374,804)	$219,699,522
Sumas	($599,950)	$8,753,305
Whitehorn	($2,030,514)	$17,998,728
Baker Hydro Relicensing	($998,866)	$31,784,220
Miscellaneous Operating Expense	$995,982	
Property Taxes	$1,390,893	
Director and Officers Insurance	$205,413	
Property and Liability Insurance	($778,678)	
Pension Plan	($2,741,878)	
Wage Increase	($3,143,028)	
Employee Insurance	($935,975)	
Regulatory Assets and Liabilities	($5,938,530)	($110,617,943)
Fredonia Power Plant	($1,057,594)	$41,512,955
Mint Farm Deferral	($3,515,856)	$28,559,231
Net Interest on SSCM to IRS	($1,471,578)	($1,323,561)
Production Adjustment	($1,755,774)	$18,925,446
Wild Horse Expansion Deferral	($1,863,011)	$2,806,055
Wild Horse Solar	$122,100	($3,663,687)
Aircraft Costs	$0	$0
Normalize Inj. & Damages Exp.	$0	$0
Elimination of Equity Return on Mint Farm	$0	$0
TOTAL	**$50,698,268**	**$329,462,617**

APPENDIX B

The table below presents the uncontested electric restating and pro forma adjustments and their impact on NOI or rate base:

Uncontested Restating and Pro Forma Adjustments – Electric

Adjustment	NOI	Rate Base
Actual Results of Operations	$225,331,768	$3,464,213,140
Temperature Normalization	($12,235,767)	
Federal Income Tax	($19,308,574)	
Tax Benefit of Pro Forma Interest (*)	($1,104,799)	
Pass-Through Revenue and Expense	($640,213)	
Bad Debts	$1,021,353	
Excise Tax & Filing Fee	$264,096	
Montana Energy Tax (*)	$50,981	
Interest on Customer Deposits	($61,479)	
SFAS 133	$4,899,699	
Rate Case Expense	$380,361	
Deferred Gains/Losses on Property Sales	($247,166)	
Investment Plan (*)	($143,722)	
Incentive Pay	$1,137,979	
Merger Cost Savings and Rate Credits	$568,233	
Storm Damage	($6,176,024)	
Depreciation	$9,109,591	$4,554,795
Fleet Vehicles	$1,272,207	$7,448,028
Total	**$204,118,524**	**$3,476,215,963**

(*) Although dollar differences exist between parties due to differences in the underlying inputs used for the calculating these adjustments (Tax Benefit of Pro Forma Interest, Montana Electric Energy Tax, Investment Plan), these adjustments are uncontested as to methodology.

APPENDIX C

The table below presents the contested gas restating and pro forma adjustments and their impact on NOI or rate base:

Contested Restating and Pro Forma Adjustments – Gas

Adjustment	NOI	Rate Base
Revenue & Expenses	$20,539,623	
Net Interest Due to IRS for SSCM	($1,018,402)	($915,968)
Miscellaneous Operating Expense	$444,551	
Property Taxes	($1,053,408)	
D&O Insurance	$142,454	
Property and Liability Insurance	$234,055	
Pension Plan	($1,480,293)	
Wage Increase	($1,599,663)	
Employee Insurance	($505,317)	
Jackson Prairie Plant Adjustment	$0	$0
Aircraft Costs	$0	$0
Normalize Injuries & Damages	$0	$0
Total	**$16,714,234**	**($915,968)**

APPENDIX D

The table below presents the uncontested gas restating and pro forma adjustments and their impact on NOI or rate base:

Uncontested Restating and Pro Forma Adjustments – Gas

Adjustment	NOI	Rate Base
Actual Results of Operations	$111,350,201	$1,476,214,962
Temperature Normalization	($8,781,321)	
Federal Income Tax	$1,028,039	
Tax Benefit of Pro Forma Interest (*)	($8,726,982)	
Depreciation Study	($6,218,349)	($3,109,174)
Pass-Through Revenue and Expense	$342,920	
Bad Debts	$454,572	
Excise Tax & Filing Fee	$693,130	
Interest on Customer Deposits	($30,273)	($6,973,756)
Rate Case Expense	$153,958	
Deferred Gaines/Losses	($313,412)	
Investment Plan (*)	($88,119)	
Incentive Pay	$615,785	
Merger Savings	$311,112	
Fleet Vehicles	$696,545	$4,077,858
Total	**$91,487,806**	**$1,470,209,890**

(*) Although dollar differences exist between parties due to differences in the underlying inputs used for the calculating these adjustments, (Tax Benefit of Pro Forma Interest, Investment Plan) these adjustments are uncontested as to methodology.

APPENDIX E

Staff
10.34

PUGET SOUND ENERGY
AMORTIZATION MINT FARM DEFERRAL
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION		TEST YEAR	RATE YEAR	ADJUSTMENT
1	**OPERATING EXPENSE FIXED COSTS**				
2	AMORT MINT FARM		$ -	$ 4,632,071	$ 4,632,071
3	MINT FARM DEFERRAL BALANCE		$ (776,937)	$ -	$ 776,937
4	TOTAL AMORTIZATION MINT FARM		**(776,937)**	**4,632,071**	**5,409,009**
5					
6	INCREASE (DECREASE) OPERATING EXPENSES				**5,409,009**
7					
8	INCREASE (DECREASE) FIT	35%			**(1,893,153)**
9					
10	INCREASE (DECREASE) NOI				**(3,515,856)**
11					
12	**RATE BASE**				
13	MINT FARM AMA GROSS - DEF & INT.		110,252	46,359,974	$ 46,249,723
14	MINT FARM AMA ACCUMULATED AMORTIZATION		-	($2,312,437)	$ (2,312,437)
15	MINT FARM AMA ACCUMULATED DEFERRED FIT		(38,583)	($15,416,638)	$ (15,378,055)
16	TOTAL MINT FARM RATE BASE		**$ 71,668**	**$28,630,899**	**$28,559,231**

This adjustment is updated based on Exhibit No. JHS 33, PSE response to Staff DR 264 (b), which includes a 10-year amortization period and includes carrying costs. This adjustment is modified to include actual data through November 2009 and actual deferred variable costs, as shown in Exhibit No. JHS-27C, Account 18600361. All estimated input data included in this adjustment is subject to true-up.

Puget Sound Energy
Mint Farm Deferral
Amortization starts April 01, 2010 and ends Mar 01, 2025 (180 months)
Amortization Schedule Adapted Accounting Procedures Docket NO. UE-082128

	Includes Carrying Costs										
	Deferral	Deferral									
Month/Period	Monthly Activity (a)	Balance (b)	AMA Gross Balance (c)	Monthly Amortization (d) = (b) / 120	Accumulated Amortization ∑ - (d) = (e)	AMA Accum. Amortization (f)	AMA Net (g) = (c) + (f)	Monthly DFIT (h) = (-(a) * 35%) + ((d) * 35%)	Accumulated DFIT ∑ - (h) = (i)	Accum DFIT AMA (j)	AMA net of Accum DFIT (l) = (g) + (j)
Beginning		$0									
Dec-08	$3,035,781	$3,035,781						(1,062,523)	(1,062,523)		
Jan-09	4,280,883	7,316,665						(1,498,309)	(2,560,833)		
Feb-09	1,426,810	8,743,475						(499,384)	(3,060,216)		
Mar-09	2,328,948	11,072,423						(815,132)	(3,875,348)		
Apr-09	3,267,435	14,339,859						(1,143,602)	(5,018,951)		
May-09	3,814,593	18,154,451						(1,335,107)	(6,354,058)		
Jun-09	4,010,954	22,165,405						(1,403,834)	(7,757,892)		
Jul-09	2,707,735	24,873,140						(947,707)	(8,705,599)		
Aug-09	708,641	25,581,781						(248,024)	(8,953,623)		
Sep-09	(310,908)	25,270,873						108,818	(8,844,805)		
Oct-09	2,516,195	27,787,068						(880,668)	(9,725,474)		
Nov-09	2,670,313	30,457,380	16,964,134				16,964,134	(934,609)	(10,660,083)	(5,937,447)	11,026,687
Dec-09	3,693,597	34,150,977	19,529,658				19,529,658	(1,292,759)	(11,952,842)	(6,835,380)	12,694,278
Jan-10	3,671,314	37,822,291	22,097,192				22,097,192	(1,284,960)	(13,237,802)	(7,734,017)	14,363,175
Feb-10	3,840,956	41,663,247	24,739,917				24,739,917	(1,344,335)	(14,582,136)	(8,658,971)	16,080,946
Mar-10	3,793,730	45,456,977	27,544,264		-	-	27,544,264	(1,327,806)	(15,909,942)	(9,640,493)	17,903,772
Apr-10	942,258	46,399,235	30,312,761	378,808	(378,808)	(15,784)	30,296,978	(197,208)	(16,107,149)	(10,603,942)	19,693,036
May-10		46,399,235	32,825,435	386,660	(765,468)	(63,462)	32,761,973	135,331	(15,971,818)	(11,466,691)	21,295,282
Jun-10		46,399,235	35,012,044	386,660	(1,152,129)	(143,362)	34,868,682	135,331	(15,836,487)	(12,204,039)	22,664,643
Jul-10		46,399,235	36,918,707	386,660	(1,538,789)	(255,483)	36,663,224	135,331	(15,701,156)	(12,832,128)	23,831,096
Aug-10		46,399,235	38,683,022	386,660	(1,925,449)	(399,827)	38,283,195	135,331	(15,565,825)	(13,399,118)	24,884,077
Sep-10		46,399,235	40,430,764	386,660	(2,312,110)	(576,392)	39,854,373	135,331	(15,430,494)	(13,949,030)	25,905,342
Oct-10		46,399,235	42,086,620	386,660	(2,698,770)	(785,178)	41,301,441	135,331	(15,295,163)	(14,455,504)	26,845,937
Nov-10		46,399,235	43,526,371	386,660	(3,085,430)	(1,026,187)	42,500,184	135,331	(15,159,832)	(14,875,064)	27,625,120
Dec-10		46,399,235	44,700,959	386,660	(3,472,090)	(1,299,417)	43,401,542	135,331	(15,024,501)	(15,190,540)	28,211,002
Jan-11		46,399,235	45,568,675	386,660	(3,858,751)	(1,604,868)	43,963,807	135,331	(14,889,170)	(15,387,332)	28,576,475
Feb-11		46,399,235	46,123,381	386,660	(4,245,411)	(1,942,542)	44,180,839	135,331	(14,753,838)	(15,463,294)	28,717,545
Mar-11		46,399,235	46,359,974	386,660	(4,632,071)	(2,312,437)	44,047,538	135,331	(14,618,507)	(15,416,638)	28,630,899
Apr-11		46,399,235	46,399,235	386,660	(5,018,732)	(2,698,770)	43,700,465	135,331	(14,483,176)	(15,295,163)	28,405,302
May-11		46,399,235	46,399,235	386,660	(5,405,392)	(3,085,430)	43,313,805	135,331	(14,347,845)	(15,159,832)	28,153,973
Jun-11		46,399,235	46,399,235	386,660	(5,792,052)	(3,472,090)	42,927,145	135,331	(14,212,514)	(15,024,501)	27,902,644
Jul-11		46,399,235	46,399,235	386,660	(6,178,713)	(3,858,751)	42,540,484	135,331	(14,077,183)	(14,889,170)	27,651,315
Aug-11		46,399,235	46,399,235	386,660	(6,565,373)	(4,245,411)	42,153,824	135,331	(13,941,852)	(14,753,838)	27,399,986
Sep-11		46,399,235	46,399,235	386,660	(6,952,033)	(4,632,071)	41,767,164	135,331	(13,806,521)	(14,618,507)	27,148,656
Oct-11		46,399,235	46,399,235	386,660	(7,338,693)	(5,018,732)	41,380,504	135,331	(13,671,190)	(14,483,176)	26,897,327
Nov-11		46,399,235	46,399,235	386,660	(7,725,354)	(5,405,392)	40,993,843	135,331	(13,535,859)	(14,347,845)	26,645,998
Dec-11		46,399,235	46,399,235	386,660	(8,112,014)	(5,792,052)	40,607,183	135,331	(13,400,527)	(14,212,514)	26,394,669
Jan-12		46,399,235	46,399,235	386,660	(8,498,674)	(6,178,713)	40,220,523	135,331	(13,265,196)	(14,077,183)	26,143,340
Feb-12		46,399,235	46,399,235	386,660	(8,885,335)	(6,565,373)	39,833,862	135,331	(13,129,865)	(13,941,852)	25,892,011
Mar-12		46,399,235	46,399,235	386,660	(9,271,995)	(6,952,033)	39,447,202	135,331	(12,994,534)	(13,806,521)	25,640,681
Apr-12		46,399,235	46,399,235	386,660	(9,658,655)	(7,338,693)	39,060,542	135,331	(12,859,203)	(13,671,190)	25,389,352
May-12		46,399,235	46,399,235	386,660	(10,045,315)	(7,725,354)	38,673,881	135,331	(12,723,872)	(13,535,859)	25,138,023
Jun-12		46,399,235	46,399,235	386,660	(10,431,976)	(8,112,014)	38,287,221	135,331	(12,588,541)	(13,400,527)	24,886,694
Jul-12		46,399,235	46,399,235	386,660	(10,818,636)	(8,498,674)	37,900,561	135,331	(12,453,210)	(13,265,196)	24,635,365
Aug-12		46,399,235	46,399,235	386,660	(11,205,296)	(8,885,335)	37,513,901	135,331	(12,317,879)	(13,129,865)	24,384,035
Sep-12		46,399,235	46,399,235	386,660	(11,591,957)	(9,271,995)	37,127,240	135,331	(12,182,547)	(12,994,534)	24,132,706
Oct-12		46,399,235	46,399,235	386,660	(11,978,617)	(9,658,655)	36,740,580	135,331	(12,047,216)	(12,859,203)	23,881,377
Nov-12		46,399,235	46,399,235	386,660	(12,365,277)	(10,045,315)	36,353,920	135,331	(11,911,885)	(12,723,872)	23,630,048
Dec-12		46,399,235	46,399,235	386,660	(12,751,938)	(10,431,976)	35,967,259	135,331	(11,776,554)	(12,588,541)	23,378,719
Jan-13		46,399,235	46,399,235	386,660	(13,138,598)	(10,818,636)	35,580,599	135,331	(11,641,223)	(12,453,210)	23,127,389
Feb-13		46,399,235	46,399,235	386,660	(13,525,258)	(11,205,296)	35,193,939	135,331	(11,505,892)	(12,317,879)	22,876,060

Line No.	Mint Farm Deferral Fixed & Variable Costs	Dec 2008	Jan 2009	Feb 2009	Mar 2009	Apr 2009	May 2009	Jun 2009	Jul 2009	Aug 2009	Sep 2009	Oct 2009	Nov 2009	Dec 2009	Jan 2010	Feb 2010	Mar 2010	Apr 2010 prorated to 04/07/10	Total
1	Rate Base (11/09 AMA)	247,005,111	242,601,906	243,177,319	243,167,452	242,129,463	241,655,832	241,728,050	241,474,787	241,201,268	240,911,253	240,343,135	240,322,401	237,626,997	237,626,997	237,626,997	237,626,997	237,626,997	
2	ROR (pre-tax) (7.00% ¸ 65%)	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	
3	Return on Ratebase	26,600,550	26,126,359	26,188,327	26,187,264	26,075,481	26,024,474	26,032,252	26,004,977	25,975,521	25,944,289	25,883,107	25,880,874	25,590,600	25,590,600	25,590,600	25,590,600	25,590,600	440,876,473
4	Monthly Recovery (26 days,																		
5	Dec 5 -31/2008)	1,859,178	2,177,197	2,182,361	2,182,272	2,172,957	2,168,706	2,169,354	2,167,081	2,164,627	2,162,024	2,156,926	2,156,740	2,132,550	2,132,550	2,132,550	2,132,550	497,595	34,747,217
6	O&M -Variable net of Market Cr.	388,283	654,908	(1,852,151)	(1,294,569)	120,849	535,172	241,402	(769,060)	(2,781,700)	(3,835,231)	(1,250,377)	(1,199,837)	0	0	0	0	0	(11,042,312)
7	O&M-Fixed	31,475	526,870	457,247	578,428	120,893	229,310	683,806	364,389	366,747	403,620	642,913	724,826	540,919	488,175	626,968	548,624	180,585	7,515,794
8	Depreciation	591,536	706,527	398,878	601,823	602,342	601,339	601,670	602,162	602,368	602,249	602,397	603,094	608,412	608,412	608,412	608,412	141,963	9,691,998
9	Property Insurance	50,471	61,279	61,279	61,279	30,848	30,848	30,848	30,848	30,848	30,848	30,848	30,848	30,848	30,848	30,848	30,848	7,198	611,682
10	Property Tax	103,456	107,958	107,968	112,345	107,958	106,989	107,958	107,958	107,958	107,958	107,958	107,958	107,958	107,958	107,958	107,958	25,190	1,751,444
11	Subtotal Return and Expenses	3,024,399	4,234,739	1,355,582	2,241,578	3,155,846	3,672,364	3,835,038	2,503,378	490,848	(528,532)	2,290,664	2,423,628	3,420,688	3,367,943	3,506,737	3,428,392	852,531	43,275,823
12																			
13	Cumltv Deferral Balance	3,024,399	7,259,138	8,614,720	10,856,298	14,012,144	17,684,508	21,519,546	24,022,924	24,513,772	23,985,240	26,275,905	28,699,533	32,120,220	35,488,163	38,994,900	42,423,292	43,275,823	402,770,528
14																			
15	Average Deferral Balance	1,512,200	5,141,769	7,936,929	9,735,509	12,434,221	15,848,326	19,602,027	22,771,235	24,268,348	24,249,506	25,130,573	27,487,719	30,409,876	33,804,192	37,241,532	40,709,096	42,849,557	381,132,617
16	Rate of return (7.00% ¸ 65%)	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	
17	Carrying Cost	11,382	46,144	71,229	87,370	111,589	142,229	175,916	204,357	217,793	217,624	225,531	246,685	272,909	303,371	334,219	365,338	89,728	3,123,412
18																			
19	Cumltv carrying cost	11,382	57,526	128,755	216,125	327,714	469,943	645,858	850,216	1,068,009	1,285,632	1,511,163	1,757,848	2,030,757	2,334,128	2,668,347	3,033,685	3,123,412	21,520,500
20																			
21	Deferral with Carrying Cost	3,035,781	7,316,665	8,743,475	11,072,423	14,339,859	18,154,451	22,165,405	24,873,140	25,581,781	25,270,873	27,787,042	30,457,380	34,150,977	37,822,291	41,663,247	45,456,977	46,399,235	424,291,002
22																			
23	Deferral Fixed Costs Amount	3,035,781	4,280,883	1,426,810	2,328,948	3,267,435	3,814,593	4,010,954	2,707,735	708,641	(310,908)	2,516,195	2,670,313	3,693,597	3,671,314	3,840,956	3,793,730	942,258	46,399,235

APPENDIX F

Staff

10.38

PUGET SOUND ENERGY
ADJUSTMENT 10.38 AMORTIZATION OF WILD HORSE EXPANSION
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008
GENERAL RATE INCREASE

LINE NO.	DESCRIPTION	TEST YEAR	RATE YEAR	ADJUSTMENT
1	**OPERATING EXPENSE FIXED COSTS**			
2	AMORTIZATION OF FIXED & VARIABLE COST DEFERRAL	$ -	$ 2,866,170	$ 2,866,170
3	DEFERRAL OF WH EXPANSION FIXED COSTS	$ -	$ -	$ -
4	TOTAL AMORTIZATION WILD HORSE EXPANSION	-	2,866,170	2,866,170
5				
6	INCREASE (DECREASE) OPERATING EXPENSES			2,866,170
7				
8	INCREASE (DECREASE) FIT	35%		(1,003,159)
9				
10	INCREASE (DECREASE) NOI			(1,863,011)
11				
12	**RATE BASE**			
13	WILD HORSE EXPANSION AMA GROSS - DEF	-	5,744,513	$ 5,744,513
14	WILD HORSE EXPANSION AMA ACCUMULATED AMORTIZA	-	($1,427,505)	$ (1,427,505)
15	WILD HORSE EXPANSION AMA ACCUMULATED DEFERRED	-	($1,510,953)	$ (1,510,953)
16	TOTAL WILD HORSE EXPANSION RATE BASE	$ -	2,806,055	2,806,055

This adjustment is updated based Exhibit No. JHS-34, PSE's Response to Staff DR 265-b, which is equivalent to PSE's rebuttal filing of this adjustment recalculated to include carrying costs and include deferred variable costs, net of market price offset. This adjustment includes actual data through December 2009. All estimated input data included in this adjustment is subject to true-up.

Puget Sound Energy
WILD HORSE EXPANSION FIXED COST DEFERRAL
Amortization starts April 01, 2010 and ends Mar 01, 2012 (24 months)

Month/Period	Includes Fixed & Variable Costs Deferral Monthly Activity (a)	Deferral Balance (b)	AMA Gross Balance (c)	Monthly Amortization (d) = (b) / 24mos.(2yrs.)	Accumulated Amortization prior mo - (d) = (e)	AMA Accum. Amortization (f)	AMA Net (g) = (c) + (f)	Monthly DFIT (h) = (-(a) * 35%) + ((d) * 35%)	Accumulated DFIT prior mo - (h) = (i)	Accum DFIT AMA (j)	AMA net of Accum DFIT (l) = (g) + (j)
Beginning		$0									
Nov-09	$667,384	$667,384						(233,585)	(233,585)		
Dec-09	1,093,051	1,760,435						(382,568)	(616,152)		
Jan-10	1,223,899	2,984,335						(428,365)	(1,044,517)		
Feb-10	1,234,695	4,219,029						(432,143)	(1,476,660)		
Mar-10	1,245,490	5,464,519						(435,921)	(1,912,582)		
Apr-10	292,168	5,756,687		227,688	(227,688)			(22,568)	(1,935,149)		
May-10		5,756,687		239,862	(467,550)			83,952	(1,851,198)		
Jun-10		5,756,687		239,862	(707,412)			83,952	(1,767,246)		
Jul-10		5,756,687		239,862	(947,274)			83,952	(1,683,294)		
Aug-10		5,756,687		239,862	(1,187,136)			83,952	(1,599,343)		
Sep-10		5,756,687		239,862	(1,426,998)			83,952	(1,515,391)		
Oct-10		5,756,687	4,376,181	239,862	(1,666,860)		4,376,181	83,952	(1,431,439)	(1,362,570)	3,013,611
Nov-10		5,756,687	4,828,097	239,862	(1,906,722)		4,828,097	83,952	(1,347,488)	(1,468,626)	3,359,471
Dec-10		5,756,687	5,206,662	239,862	(2,146,584)		5,206,662	83,952	(1,263,536)	(1,542,013)	3,664,649
Jan-11		5,756,687	5,488,687	239,862	(2,386,446)		5,488,687	83,952	(1,179,584)	(1,574,615)	3,914,072
Feb-11		5,756,687	5,668,270	239,862	(2,626,308)		5,668,270	83,952	(1,095,633)	(1,564,366)	4,103,904
Mar-11		5,756,687	5,744,513	239,862	(2,866,170)	(1,427,505)	4,317,008	83,952	(1,011,681)	(1,510,953)	2,806,055
Apr-11		5,756,687	5,756,687	239,862	(3,106,032)	(1,666,860)	4,089,827	83,952	(927,729)	(1,431,439)	2,658,387
May-11		5,756,687	5,756,687	239,862	(3,345,894)	(1,906,722)	3,849,965	83,952	(843,778)	(1,347,488)	2,502,477
Jun-11		5,756,687	5,756,687	239,862	(3,585,756)	(2,146,584)	3,610,103	83,952	(759,826)	(1,263,536)	2,346,567
Jul-11		5,756,687	5,756,687	239,862	(3,825,618)	(2,386,446)	3,370,241	83,952	(675,874)	(1,179,584)	2,190,657
Aug-11		5,756,687	5,756,687	239,862	(4,065,480)	(2,626,308)	3,130,379	83,952	(591,923)	(1,095,633)	2,034,746
Sep-11		5,756,687	5,756,687	239,862	(4,305,341)	(2,866,170)	2,890,517	83,952	(507,971)	(1,011,681)	1,878,836
Oct-11		5,756,687	5,756,687	239,862	(4,545,203)	(3,106,032)	2,650,655	83,952	(424,019)	(927,729)	1,722,926
Nov-11		5,756,687	5,756,687	239,862	(4,785,065)	(3,345,894)	2,410,793	83,952	(340,068)	(843,778)	1,567,016
Dec-11		5,756,687	5,756,687	239,862	(5,024,927)	(3,585,756)	2,170,931	83,952	(256,116)	(759,826)	1,411,105
Jan-12		5,756,687	5,756,687	239,862	(5,264,789)	(3,825,618)	1,931,069	83,952	(172,164)	(675,874)	1,255,195
Feb-12		5,756,687	5,756,687	239,862	(5,504,651)	(4,065,480)	1,691,207	83,952	(88,212)	(591,923)	1,099,285
Mar-12		5,756,687	5,756,687	239,862	(5,744,513)	(4,305,341)	1,451,345	83,952	(4,261)	(507,971)	943,374

Line No.	Estimate of Wild Horse Expansion Fixed & Variable Costs	Nov 2009 prorated to 11/9/09 COD	Dec 2009	Jan 2010	Feb 2010	Mar 2010	Apr 2010 prorated to 04/07/10	Total
1	Rate Base (11/2010 AMA)	74,513,113	74,513,113	74,513,113	74,513,113	74,513,113	74,513,113	
2	Rate of return (pre-tax) (7.00% ¸ 65%)	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	
3	Annualized Return on Ratebase	8,024,489	8,025,062	8,025,062	8,025,062	8,025,062	8,025,062	48,149,800
4								
5	Monthly Recovery, prorated when applicable	714,865	671,178	668,755	668,755	668,755	156,043	3,548,351
6	Variable Costs Net of Market Offset	-373,964	-105,572	0	0	0	0	(479,535)
7	Fixed Costs							
8	O&M	324,294	516,618	163,868	163,868	163,868	38,236	1,370,750
9	Depreciation			345,009	345,009	345,009	80,502	1,115,528
10	Property Tax			25,187	25,187	25,187	5,877	81,439
11	Subtotal Return and Expenses	665,195	1,082,224	1,202,819	1,202,819	1,202,819	280,658	5,636,533
12								
13	Cumulative Deferral Balance	665,195	1,747,420	2,950,238	4,153,057	5,355,876	5,636,533	20,508,319
14								
15	Average Deferral Balance	332,598	1,206,308	2,348,829	3,551,648	4,754,466	5,496,204	17,690,053
16	Rate of return (7.00% ¸ 65%)	10.77%	10.77%	10.77%	10.77%	10.77%	10.77%	
17	Carrying Cost	2,189	10,827	21,081	31,876	42,671	11,510	120,154
18								
19	Cumulative carrying cost	2,189	13,016	34,096	65,972	108,644	120,154	344,070
20								
21	Deferral with Carrying Cost	667,384	1,760,435	2,984,335	4,219,029	5,464,519	5,756,687	20,852,390
22								
23	Deferral Fixed & Variable Costs Amount - Monthly	667,384	1,093,051	1,223,899	1,234,695	1,245,490	292,168	5,756,687