[Service Date April 2, 2010]

BEFORE THE WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND	)	
TRANSPORTATION COMMISSION,	)	DOCKETS UE-090704 and
	)	UG-090705 (*consolidated)*
Complainant,	)	
v.	)	ORDER 11
	)	
PUGET SOUND ENERGY, INC.,	)	REJECTING TARIFF SHEETS;
	)	AUTHORIZING AND REQUIRING
Respondent.	)	COMPLIANCE FILING
. . . .	)	

***Synopsis**: The Commission rejects revised tariff sheets Puget Sound Energy, Inc. (PSE or the Company) filed on May 8, 2009, by which the Company proposed to increase electric rates by 7.4 percent and natural gas rates by 2.2 percent. In lieu of the Company's proposed increases in rates, the Commission authorizes and requires PSE to file tariff sheets that will result in fair, just, reasonable and sufficient increases of approximately 2.8 percent for electric rates and 0.8 percent for natural gas rates. The Commission accepts a number of uncontested pro forma adjustments proposed by PSE and approves and adopts two uncontested settlement agreements that resolve, respectively, issues of electric and natural gas rate spread and rate design. Among several contested issues, the Commission denies the Company's proposed pro forma adjustments that were not demonstrated to be known and measurable and not offset by other factors. The Commission, for example, rejected PSE's proposal to reduce electric load to account for conservation load loss the Company claimed was not accounted for in the 2008 test year. However, the Commission adjusted rates through the application of a "production factor" to account for the reduced load PSE projects for the2010-2011 rate year, including load loss attributable to conservation. The Commission sets the Company's authorized rate of return, allowing a 10.1 percent return on the 46 percent of PSE's capital structure that represents equity investment, a 6.7 percent cost of long-term debt that represents 50 percent of the Company's capital structure and a 2.5 percent cost of short-term debt that represents the balance of PSE's capital structure. Overall, this results in an 8.10 percent rate of return for the Company. The Commission determines that PSE's acquisition of the Mint Farm combined cycle combustion turbine generation facility was prudent and allows for recovery of the associated costs in rates. In addition, the Commission finds prudent on the basis of uncontested evidence the Company's acquisition of a number of other power assets and finds reasonable the sale of PSE's White River assets.*

TABLE OF CONTENTS

SUMMARY

1 **PROCEEDINGS:** On May 8, 2009, Puget Sound Energy, Inc. (PSE or the Company), filed with the Washington Utilities and Transportation Commission (Commission) certain tariff revisions designed to increase its general rates for electric service (Docket UE-090704) and gas service (Docket UG-090705) to customers in Washington. The proposed revisions provided for a general rate increase of 7.4 percent for the electric tariffs and 2.2 percent for the gas tariffs. The Commission suspended operation of the tariffs by Order 01, entered in these dockets following the May 28, 2009, open meeting. By Order 02, entered on June 8, 2009, the Commission consolidated these dockets.

2 At various times established in its procedural schedule and by several orders the Commission accepted prefiled testimony and exhibits from the Company, the Commission's regulatory staff (Commission Staff or Staff),[1] and other parties. The Company revised its as-filed proposal several times, both up and down, during the pendency of these proceedings, finally proposing to recover additional revenue of $110,303,260 in electric rates and $28,464,116 in natural gas rates.[2]

3 The Commission conducted evidentiary hearings on January 19 – 21, 2010. In addition, the Commission conducted public comment hearings in separate locations in PSE's service territory on December 7 and 10, 2010, and on January 19, 2010, during which it received into the record oral comments and exhibits from interested members of the public.[3] The parties filed briefs and reply briefs on February 19, 2010, and March 2, 2010, respectively.

[1] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See RCW 34.05.455.*

[2] PSE Initial Brief at ¶ 1.

[3] The Commission also received written comments from members of the public through the close of the record on January 25, 2010. These comments are identified in the formal record as Exhibit B-1.

4 **PARTY REPRESENTATIVES:** Sheree Strom Carson and Jason Kuzma, Perkins Coie, Bellevue, Washington, represent PSE. Simon ffitch, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington Office of Attorney General (Public Counsel). Robert D. Cedarbaum, Senior Assistant Attorney General and Michael Fassio, Assistant Attorney General, Olympia, Washington, represent the Commission Staff.

5 S. Bradley Van Cleve and Irion Sanger, Davison Van Cleve, Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Chad M. Stokes, Cable Huston Benedict Haagensen & Lloyd LLP, Portland, Oregon, represents Northwest Industrial Gas Users (NWIGU). Elaine L. Spencer, Graham & Dunn PC, Seattle, Washington, represents Seattle Steam Company (Seattle Steam). Michael L. Kurtz and Kurt J. Boehm, Boehm, Kurtz & Lowry, Cincinnati, Ohio, represent the Kroger Co., on behalf of its Fred Meyer Stores and Quality Food Centers divisions (Kroger). Norman Furuta, Associate Counsel, Department of the Navy, San Francisco, California, represents the Federal Executive Agencies (FEA). Ronald L. Roseman, Attorney, Seattle, Washington, represents the Energy Project. John A. Cameron, Davis Wright Tremaine LLP, represents Cost Management Services, Inc. Damon E. Xenopoulos, Brickfield, Burchette, Ritts & Stone, PC, Washington, D.C., represents Nucor Steel Seattle, Inc. (Nucor). David S. Johnson, attorney, represents the Northwest Energy Coalition (NWEC).

6 **COMMISSION DETERMINATIONS**: The Commission suspended and set for hearing the rates PSE originally proposed. Based on the record of this proceeding we find that neither the Company's as-filed rates, nor the revised rate requests by PSE made at the conclusion of the advocacy phase, are fair, just and reasonable. Accordingly, we must determine fair, just, reasonable and sufficient rates based on the record before us.[4] We find on the basis of the evidence presented that PSE requires rate relief and therefore determine that the Company should be authorized to file rates in compliance with our decisions, as discussed in detail below. When implemented via a compliance filing we require the Company to make, the resulting rates will be fair, just, reasonable and sufficient, and neither unduly discriminatory nor preferential. The precise revenue deficiency for electric service must be determined during the compliance filing phase of this proceeding because the disallowances to power costs that must be reflected for Tenaska and March Point depend on our decisions in this Final Order concerning power costs and the

---

[4] RCW 80.28.020.

production factor.[5] We find a revenue deficiency of $10,149,229 for natural gas and authorize PSE to file rates to recover additional revenue in this amount. The Company's new rates will be effective no earlier than April 7, 2010.

<u>MEMORANDUM</u>

I. Background and Procedural History

7 PSE filed revised tariff sheets on May 8, 2009, that would have increased its rates for electric and natural gas service provided to customers in Washington by, respectively, $148,148,000 (7.4 percent) and $27,199,177 (2.2 percent), if allowed to become effective as proposed. The Commission, however, suspended operation of the tariffs by Order 01 entered in the respective electric and natural gas dockets (*i.e.*, Dockets UE-090704 and UG-090705) following its regularly scheduled Open Meeting on May 28, 2009. The Commission consolidated these dockets by Order 02, entered on June 8, 2009. Following a prehearing conference held at Olympia, Washington on June 22, 2009, the Commission entered Order 04 - Prehearing Conference Order in which it granted several petitions to intervene and set a procedural schedule.[6]

8 In addition to its initial direct testimony filed with the proposed tariff sheets, PSE filed three motions requesting leave to file supplemental direct testimony: the first on August 8, 2009[7]; the second on August 25, 2009[8], and the third on September 28, 2009.[9] The Commission granted these motions. With the filing of its supplemental testimony on September 28, 2009, the Company's requests for increased revenue increased to $153,640,326 for electric and $30,408,378 for natural gas.

---

[5] Reviewing the evidence available to us at this time, we estimate a revenue deficiency of $56,204,849 for electric. This amount will be adjusted modestly to account for the Tenaska and March Point 2 disallowances and other matters affecting the production factor adjustment, as discussed later in this Order.

[6] Order 03 in this proceeding is a protective order, entered to facilitate the discovery process by providing appropriate treatment for commercially sensitive information.

[7] Order 06 - Granting Leave to File Supplemental and Revised Testimony and Exhibits, August 12, 2009.

[8] Order 07 - Granting Leave to File Supplemental and Revised Testimony and Exhibits, September 10, 2009.

[9] Order 08 - Granting Leave to File Supplemental and Revised Testimony and Exhibits; Shortening Response Time for Discovery, September 20, 2009.

9 On November 17, 2009, Staff, Public Counsel, ICNU, Kroger, NWIGU, NUCOR and FEA filed their respective response testimonies and exhibits. Staff and Public Counsel sponsored full revenue requirements cases including cost of capital witnesses. The other intervening parties sponsored witnesses addressing a limited scope of issues. Staff filed its motion requesting leave to file supplemental testimony on December 11, 2009, which the Commission granted in Order 09, entered on December 28, 2009.

10 The Company filed rebuttal testimony on December 17, 2009. After accepting some adjustments proposed by the responding parties and updating or correcting certain other information, the Company revised its electric revenue requirement request downward to $113,299,963, resulting in a proposed 5.7 percent average increase in electric rates.[10] PSE also revised its natural gas revenue requirement request downward to $28,464,116, resulting in a proposed 2.3 percent average increase in natural gas rates.[11]

11 Tables 1 and 2 show, respectively, the electric and natural gas revenue requirement requests and recommendations supported by the Company and parties through the briefing stage of these proceedings.

TABLE 1
Proposed Total Adjustments to Annual Revenue Requirement ($M) Relative to Current Rates (Electric)

	As-Filed	Supplemental	Response	Rebuttal/Cross Answer	Final
PSE	$148,148,000	$153,640,326		$113, 299, 963	$110,303,620
Staff			$5,826,516	$7,238,781	$10,382,994
Public Counsel			($42,541,000)	($42,506,684)	$7,900,880

[10] Exhibit EMM-5T (Markell) at 11-18.

[11] *Id.*

TABLE 2
Proposed Total Adjustments to Annual Revenue Requirement ($M) Relative to Current Rates (Natural Gas)

	As-Filed	Supplemental	Response	Rebuttal/Cross Answer	Final
PSE	$27,199,177	$30,408,378		$28,464,116	$28,464,116
Staff			$7,130,348	$7,926,564	$9,233,330
Public Counsel			($330,000)	($329,525)	$2,105,652

12 On December 16, 2009, the Commission accepted for filing the "Motion to Strike of Puget Sound Energy, Inc., Commission Staff, NW Energy Coalition, and the Energy Project." The moving parties asked the Commission to strike portions of the response testimony and exhibits of Public Counsel and the Kroger Co. that related to the sales of renewable energy credits (RECs) by PSE. The Commission granted the motion, removing the REC issues from these proceedings, in light of the fact they are pending determination in Docket UE-090725, which the Commission expects to bring to conclusion in the near term.[12]

13 We held public comment hearings in Bremerton on December 7, 2009, in Kirkland on December 10, 2009, and in Olympia on January 19, 2010. Twenty-one individuals, all customers of PSE, provided valuable testimony concerning their individual perspectives on the Company's requests for increased rates and related matters (*e.g.*, service quality). In addition, the Commission received into the record written comments from numerous members of the public, principally customers.[13]

14 Much of the public comment focused on the difficult economic times that are an important part of the context in which we consider PSE's request for increased rates. We keep such testimony in mind as we make decisions implementing our responsibility to set rates that stimulate efforts on the Company's part to reduce operating costs and increase efficiencies. In the current economic climate, customers must make difficult decisions concerning their spending. So, too, must PSE's management make the right decisions to aggressively control the Company's earnings

---

[12] Order 10, Granting Motion to Strike Testimony (January 8, 2010).

[13] Exhibit B-1 (Public Comments).

expectations and expenses, limit discretionary spending, and ensure that its capital investments reflect current economic conditions.

15 On January 19 – 21, 2010, the Commission held hearings in Olympia to receive evidence from the parties and to allow them an opportunity to conduct cross-examination of witnesses who prefiled testimony. These hearings also gave the Commission an opportunity to conduct inquiry from the bench. The fully developed record, including public comment and detailed evidence concerning PSE's revenue requirements and other issues, was closed on January 25, 2010, subject to submission of several responses to Commission bench requests made during the hearing. The final transcript consists of more than 800 pages and reflects the admission of prefiled testimony and exhibits sponsored by 39 witnesses. The documentary record includes approximately 550 exhibits.

16 Parties interested in the issues of electric and natural gas rate spread and rate design negotiated settlement stipulations resolving these issues. These were made part of the record during the Commission's evidentiary proceedings along with supporting testimony filed with respect to each settlement. The settling parties presented a panel of witnesses at hearing and the Commission inquired of the panel from the bench.

17 On February 19, 2010, the parties filed their Initial Briefs. On March 2, 2010, the parties filed their Reply Briefs.

II. Discussion and Decisions

A. Introduction

18 The Commission's duty under statute in the context of a general rate case proceeding is to determine an appropriate balance between the needs of the public to have safe and reliable electric and natural gas services at reasonable rates and the financial ability of the utility to provide such services on an ongoing basis. Thus, the end results of our orders in proceedings such as this one must be to establish rates that are, in the words of our governing statutes, "fair, just, reasonable and sufficient" [14] – fair to customers and to the Company's owners; just in the sense of being based solely on the record developed in the proceeding following principles of due process of law; reasonable in light of the range of possible outcomes supported by the evidence and;

---

[14] RCW 80.28.010(1) and 80.28.020.

sufficient to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms.[15]

19 As shown above in Tables 1 and 2, the parties in this proceeding advocate widely divergent end results in terms of PSE's revenue requirement. Following long-established principles of utility ratemaking and historic Commission practices, we must determine on the basis of the evidence presented what levels of prudently incurred expenses the Company will experience prospectively, and allow for recovery of those expenses. In addition, we must determine the Company's "rate base" and allow for an appropriate rate of return on that rate base.[16] This is necessary to allow the Company to recover the costs of its investments in infrastructure, repay its lenders, and provide an opportunity for the Company to earn a reasonable return, or profit, some of which may be distributed to its equity investors in the form of stock dividends. The sum of the two figures – expenses and return on rate base – constitutes the company's revenue requirement that we approve for recovery in rates.[17] The Washington Supreme Court explained this rate-making formula as follows:

> In order to control aggregate revenue and set maximum rates, regulatory commissions such as the WUTC commonly use and apply the following equation:
>
> $$R = O + B(r)$$
>
> In this equation,
>
> R is the utility's allowed revenue requirements;
> O is its operating expenses;
> B is its rate base; and
> r is the rate of return allowed on its rate base.

---

[15] *See Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944); *See also Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923).

[16] Reduced to a simple definition, rate base is the Commission-approved level of PSE's investment in facilities plus the cash, or "working capital" supplied by investors that is used to fund the Company's day-to-day operations. The Commission follows the original cost less depreciation method when determining the value of a utility's property that is used and useful in providing service to customers. *People's Organization for Washington Energy Resources v. Washington Utilities & Transportation Comm'n*, 104 Wn.2d 798, 828, 711 P.2d 319 (1985)

[17] *See Id.* at 807-09 (describing ratemaking principles and process).

> Although regulatory agencies, courts and text writers may vary these symbols and notations somewhat, this basic equation is the one which has evolved over the past century of public utility regulation in this country and is the one commonly accepted and used.[18]

20 In this case, there are a host of contested issues concerning operating expenses, rate base and rate of return. We discuss and resolve each of these issues below, arriving ultimately at revenue requirements to be recovered prospectively by PSE in its electric and natural gas rates.

21 While the amounts of PSE's revenue requirements for electric and natural gas services are hotly contested in this proceeding, the allocation of the revenue requirements to various customer classes (*e.g.*, residential; large industrial and commercial), and the design of rates to recover the allocated costs, are not contested. As to these questions, the parties achieved settlement agreements that we approve and adopt as part of this Final Order for purposes of establishing rates. We discuss these settlements in more detail below.

B. Revenue, Expense and Rate Base Restating and Pro Forma Adjustments

1. General Principles

22 In its decision in Avista Corporation's most recent general rate case proceeding, the Commission discussed in detail certain well-established general principles of utility ratemaking as applied to Washington jurisdictional utilities. [19] We find it useful to quote a portion of that discussion here:

> The Commission's long-established and well-understood ratemaking practice requires companies filing for revised rates to start with an historical test year. There is a fundamental reason for this starting point: costs, revenues, loads, and all other pertinent factors are known and can be measured with a high degree of certainty because they have, in fact, occurred. The practical value of the historical test year is that the cost, revenue and plant data are available for audit, and the test year

---

[18] *Id.* at 809.

[19] *WUTC v. Avista*, Dockets UE-090134 and UG-090135, Order 10 at ¶¶ 40-50 (December 22, 2009). (Avista 2009 GRC Order).

captures the complex relationships among the various aspects of utility costs, revenue, load, and other factors over a uniform period of time.

The Commission recognizes that the test year is a snapshot in time. The typical test year is the twelve month period preceding the rate filing, ended as of the most recent auditable results of operations.[20] A utility, however, continues to operate, incur costs (including capital additions), achieve savings, and receive revenues during the pendency of its rate review subsequent to the test year that would carry over into the year in which the rates would be effective (known as the "rate year") and beyond. The theory, well supported by ratemaking theory and past commission practice,[21] is that once the relationship is set, it will continue to provide appropriate income to the company in the future. If the utility hooks up new customers, the revenues and expenses will increase in the same proportion as existed in the test year. If new facilities are put into service to serve those customers, then the resulting revenues would not only cover the company's added expenses, but also effectively provide a return on that new investment.

However, our past decisions, and our rules, recognize that there are some expenses or investments that do not take place in the test year that, nevertheless, should be included in the rate-making formula. Thus, subject to important conditions, a company's rate filing may include restating and pro forma adjustments.[22] These are allowed to revise or update expenses, revenues, and rate base so long as there is a

---

[20] The test year is a period of company operations for which the Commission conducts a careful audit and review prior to authorizing any change in rates. *See* 1 Leonard S. Goodman, *The Process of Ratemaking* 141 (1998).

[21] *See* Charles F. Phillips, Jr., *The Regulation of Public Utilities* 196 (1993).

[22] WAC 480-07-510 (3)(e)(ii) and (iii) provide as follows:

> (ii) "Restating actual adjustments" adjust the booked operating results for any defects or infirmities in actual recorded results that can distort test period earnings. Restating actual adjustments are also used to adjust from an as-recorded basis to a basis that is acceptable for rate making. Examples of restating actual adjustments are adjustments to remove prior period amounts, to eliminate below-the-line items that were recorded as operating expenses in error, to adjust from book estimates to actual amounts, and to eliminate or to normalize extraordinary items recorded during the test period.
>
> (iii) "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.

> mechanism ensuring, and evidence establishing, that these adjustments do not disturb test year relationships.[23]

23 Thus, in Washington, we use a modified historic test year approach. We start with audited results from a recent 12 month period, but we modify those results to reflect changes that substantial evidence, timely presented, shows have occurred during the pendency of a rate case, or will occur in the rate year that begins at the conclusion of the proceeding. We have found this forward looking approach more appropriate when considering both power costs and production related assets. For example, the AURORA power cost model looks to forecasted power costs in the rate year. Those future costs can then be matched to test year loads through the production property adjustment, discussed below. This approach reduces regulatory lag without burdening ratepayers with unnecessary costs determined on the basis of the more speculative future test year approach to ratemaking that is used in some jurisdictions. Our approach strikes a balance that motivates PSE and the other utilities subject to our jurisdiction to carefully manage their costs and revenues going forward and take full advantage of their opportunity to recover fully all fixed and variable costs including a reasonable return on capital investments.

24 In this general rate case, both restating and pro forma adjustments are proposed and contested. The fundamental question posed by a contested restating adjustment – in this instance, a normalizing adjustment – is whether certain expenses recorded during the test period are extraordinary and should be adjusted to levels that are more indicative of ordinary levels for the expenses in question.

25 With respect to each of the numerous contested pro forma adjustments, the fundamental questions are whether the proposed change in expense, revenue or rate base is "known and measurable" and, if so, whether it is "offset by other factors," a concept also known as the "matching principle."

26 The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be *known* to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations,[24] and the effect of that event will be in place during the 12-month period when rates will likely be in

---

[23] Avista GRC Order at ¶¶ 41-43 (internal footnotes in original).

[24] This is also known as the "test year," "test period" or "historical test year." In this case, the test year is the 12 month period that ended December 31, 2008.

effect.[25] Furthermore, the actual amount of the change must be *measurable*. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base. There are exceptions, such as using the forward costs of gas in power cost projections, but these are few and demand a high degree of analytical rigor.

27 The matching principle requires that all factors affecting a proposed pro forma change be considered in determining the pro forma level of expense. This includes consideration of offsetting factors such as efficiency gains that may or may not be associated directly with the proposed pro forma adjustment. Offsetting factors may "cancel out" or at least mitigate the impact of a known and measurable increase in expense. If offsetting factors are not taken into account, the known and measurable change will result in overstated or understated revenue requirements. That is, a mismatch in the relationship of revenues, expenses, and rate base is created.

28 We emphasize that there are two aspects to the consideration of offsetting factors. First, there should be evidence showing consideration of whether a proposed increase in expense directly produces any offsetting benefits. For example, the Company may obtain a new computer program that automates aspects of the billing process, reducing the need for employees responsible for this process. Thus, the costs of the computer program may be partially or fully offset by the savings in wages and benefits. On the other hand, it may turn out that other demands on the Company require additional employees during the same period that exactly replace the costs of the savings in the billing function. This illustrates the other aspect of offsetting factors—contemporaneous changes in revenues or expenses that are not directly related to the proposed pro forma adjustment, but which offset its financial impacts.

29 This second aspect of the offsetting factors evaluation makes the question of remoteness from the test year important when considering proposed pro forma adjustments. The further out the point at which a proposed pro forma adjustment is known and measurable, the less sure the Commission can be that there are no offsetting factors – direct or indirect. Thus, any proposed adjustment that becomes

---

[25] This is also known as the "rate year." In this case, based on the statutory suspension date of April 7, 2010, the rate year is the 12 month period that will end April 6, 2011.

known and measurable more than a few months after the test year is inherently suspect and requires a greater showing, if it is to be allowed.[26]

30 Offsetting factors may or may not be present when adjusting for expense items, but there typically will be offsetting factors for any addition to rate base. Thus, focusing on rate base, when a utility replaces an older piece of equipment with a new, more efficient piece of equipment, there should be gains in efficiency or reduced maintenance expense. If the piece of equipment is included in rate base without reflecting these offsetting factors, a mismatch is created. Pro forma rate base adjustments often are not considered to be appropriate because the offsetting factors are extremely difficult to measure. That is, it is not possible to properly match revenues, expenses, and other relationships that constitute the entire business operation.

31 Despite this, Commission practice during recent years has allowed adjustments to rate base to bring power production facilities into rates, even though the acquisition occurred after the test period. The Commission adopted in PSE's case the Power Cost Only Rate Case ("PCORC") mechanism, and has allowed in general rate cases pro forma adjustments for major plant additions in order to match the in-service date with the start of the recovery of those investments.[27] The main reasons for allowing such adjustments were the materiality of the resource acquisition and the fact that offsetting factors were captured through the power supply and production factor adjustments.

32 In this proceeding, we are asked again to allow significant pro forma rate base additions. In addition, we are presented proposed pro forma adjustments to rate base and expense that fall further and further from the end of the test year. Many components of these adjustments are based simply on estimates or forecasts, which may have been updated one or more times during the course of the proceeding. This has placed a burden on Staff and other parties to continuously evaluate updated information, which may impact the quality of the record upon which the Commission

---

[26] The farther a proposed adjustment is removed in time from the test year, and the less time that supporting evidence is available for examination, discovery, and auditing by our staff and other parties, the greater is the Company's burden to demonstrate that the requirements guiding our consideration of adjustments to test year data have been met.

[27] In PSE's case, these include Fredrickson 1 (Docket UE-031725); Hopkins Ridge (Docket UE-050870); Wild Horse (Docket UE-060266); Goldendale (Docket UE-070565); and Whitehorn and Sumas (Docket UE-072300).

must base its decisions. It accordingly is reasonable for the Commission to establish in the context of this Order some parameters for future guidance to parties.

33 Increases in rate base and in expense and revenue items ideally are audited before they are approved for recovery in rates. They, at the least, should be auditable by Staff within a reasonable time after a company files a general rate case and well before the date set for Response Testimony. In all but exceptional cases, any rate base addition or pro forma adjustment to expense must satisfy the known and measurable requirement at the time the company makes its filing. This gives Staff and other parties adequate time to evaluate the adjustments and consider whether offsetting factors are appropriately taken into account. Such evaluation promotes a more rigorous record than would otherwise be possible. Supplemental filings can continue to be used for good cause shown, if failure to do so might seriously skew results. However, they should be used sparingly and filed prior to the deadline for Staff and others to file their responsive testimony. Should a supplemental filing not provide parties sufficient time to rigorously evaluate the new evidence and respond to it in their responsive testimony, they can request additional time to make their responsive filing, in whole or in part. Requests to make a supplemental filing later than the deadline should be accompanied by either an agreement to adjust the overall procedural schedule[28] (even if it would extend the original suspension date) or a showing of extraordinary circumstances.

34 With these principles in mind, we turn now to consideration of the contested issues, starting with proposed pro forma adjustments. There are 11 contested pro forma adjustments in this case that are not associated with rate base. Except for Power Costs, these adjustments are contested as to both the electric and the natural gas revenue requirements.

35 An additional 13 contested expense items are associated with rate base.[29] Three of these adjustments, Jackson Prairie, Net Interest Due to the IRS and Corporate Aircraft Expense, are contested as to both the electric and the natural gas revenue requirements. Jackson Prairie, is treated as a separate adjustment on the natural gas side, but is within the Power Cost adjustment on the electric side. The remaining ten adjustments associated with rate base are all on the electric side.

---

[28] We remind the parties that the Commission prefers to have six weeks from the date of the final briefs to complete the decision and order writing process.

[29] The parties dispute only expense levels on four of these adjustments, but both expense and rate base are contested on the other nine.

2. Contested Adjustments -Non-Rate Base- Electric and Natural Gas

a. General Revenues and Expenses (Adjustments 10.02 and 9.02- Conservation Phase-in Adjustment)

36 PSE proposes an adjustment to test period revenues and expenses that it calls a "conservation phase-in adjustment." This adjustment restates test period, weather-normalized loads for the Company's retail natural gas and electric customers to mitigate what it describes as "certain ratemaking consequences of the phase-in of Company-sponsored conservation that occurred during the test year."[30] The ostensible effect of the Company's proposed adjustment is to reduce test-year electric and natural gas loads to reflect the conservation achieved by its programs through the end of the test-year. The adjustment reduces test year electric loads by 124 million kWh and test year natural gas loads by 2 million therms.[31] The effect would be to increase unit rates to customers.

37 The parties' final revenue requirement presentations show the conservation phase-in adjustment decreasing electric net operating income by $6,242,791 and natural gas net operating income by $379,566. Using the conversion factors we approve in this proceeding, discussed later in this Order, PSE's proposal would increase the electric revenue requirement by $10,048,564 and the gas revenue requirement by $610,341.

38 Mr. Story and Mr. Piliaris, testifying for PSE, contend the conservation phase-in is a proper pro forma adjustment akin to weather normalization, meeting the known and measurable requirements and satisfying the matching principle.[32]

39 Staff, Public Counsel and others advocate rejection of the conservation phase-in adjustment. They argue it is not a proper pro forma adjustment, being neither known and measurable, nor taking account of offsetting factors.

40 Although the proposed conservation phase-in mechanism has novel attributes relative to what the Commission has considered in the past, it appears to be a means to achieve the ends of mechanisms that are usually referred to as "decoupling mechanisms." That is, it is an adjustment that allows the Company to recover

---

[30] Exhibit JAP-1T (Piliaris) at 19:10-12.

[31] Exhibit JAP-1T (Piliaris) at 24:1-3; Exhibit MPP-1T (Parvinen) at 13:7-8.

[32] *See* Exhibit JHS-1T (Story) at 11:11-17 and 60:1-61:1; Exhibit JAP-1T (Piliaris) at 21:1-2; and s*ee generally* Exhibit JAP-5T (Piliaris) at 19:6-23:3.

marginal revenue lost due to reduced load attributed to the Company's demand-side management (*i.e.,* conservation) programs. PSE's principal witness on this subject, Mr. Piliaris, describes it in exactly these terms.[33] When asked directly, however, Mr. Piliaris flatly denies that the Company's proposal is a form of decoupling.[34]

41 The Company's reasons for denying the conservation phase-in adjustment is a form of decoupling include the fact that PSE committed in connection with its recent transfer of ownership not to propose any form of decoupling mechanism for industrial customers for two years after the sale of the Company.[35] The transfer was consummated during the early part of 2009 following Commission approval of the settlement agreement in which PSE made this commitment. The Company also stated at the time of the transfer that it had no plans to propose decoupling at all for any customer class.[36] Public Counsel, ICNU and NWIGU argue the proposed conservation phase-in adjustment is decoupling and, therefore, PSE is barred from proposing it in its present form, which includes industrial customers.

42 However, we need not decide whether PSE's proposal is decoupling as contemplated by its commitment to make no such proposals for industrial customers. Even accepting PSE's argument that the proposed conservation phase-in adjustment is not a decoupling mechanism,[37] but rather is simply a classic pro forma adjustment, there are two reasons why, on this record, it should not be accepted.

---

[33] Tr. 557:8-13 (Piliaris) (I would characterize this [*i.e.,* the conservation phase-in adjustment] as the company has shifted its focus away from incentives per se and more towards cost recovery, and specifically the lost margin recovery, and the phase-in adjustment is a small piece of the overall lost margin recovery in the company's opinion, so the focus now is more on cost recovery.); Tr. 558:14-18 (Piliaris) ("Right now this phase-in adjustment only addresses a small piece of the lost margin recovery, and we fully intend to seek recovery of the entire lost margin due to conservation, company sponsored conservation.").

[34] Tr. 565:8-10 (Piliaris).

[35] *Re Puget Holdings and PSE*, Docket U-072375, Order 8 at ¶ 95 and Appendix A to Stipulation, page 13, Commitment 63 (December 30, 2008).

[36] *Id. and* Appendix A to Stipulation, page 13, Commitments 62 and 63.

[37] Indeed, the parties seem to agree that the proposed adjustment is not the same as a typical decoupling mechanism. The purpose of decoupling is to remove a company disincentive to conserve by "breaking the link" between the company's sales and profits. Avista 2009 GRC Order at ¶ 242 (quoting from *UTC v. PacifiCorp*, Docket UE-050684, Order 04, ¶¶ 108-110 (April 17, 2006). Here, the phase-in adjustment does not break that link. *See* NWEC Reply Brief at ¶¶ 5-6. Tr. 565:18-566:1 (Piliaris)

43 First, as argued by Staff and Public Counsel, PSE's proposal fails to take offsetting factors into account, thus not passing one of the critical tests that define proper pro forma adjustments. Staff argues that "Company-sponsored conservation is only one of many factors that influence electricity and natural gas sales."[38] Staff cites to Mr. Dittmer's testimony for Public Counsel that identifies such factors as the number of customers served, the average use per customer that can be impacted by selected end-uses (such as heat, water heat, air conditioning and other appliance or device choices), home size, building codes, economic conditions, and customer-financed measures that have nothing to do with PSE's conservation programs.[39] Mr. Piliaris acknowledged at hearing that the Company's proposal will allow it to recover lost margins from conservation even when total household use increases or remains unchanged due to new end uses.[40]

44 Mr. Dittmer, for Public Counsel, presented evidence showing overall electric usage on a total company basis has increased while overall electric usage per customer is essentially flat, notwithstanding PSE's conservation programs.[41] Public Counsel argues that "this in itself shows that offsets are occurring."[42] Mr. Dittmer testified that overall sales of gas on a company-wide basis also continue to rise and long term trends in declining use per customer were reversed between 2007 and 2008.[43]

45 PSE argues that "[w]hether or not loads are increasing is irrelevant; PSE would have had greater sales to cover increasing costs if conservation had not reduced load."[44] Public Counsel replies that:

---

[38] Staff Initial Brief at ¶ 65.

[39] *Id.* (citing Exhibit JRD-1CT (Dittmer) at 37:7-38:2).

[40] Tr. 560:1-25 and Tr. 561:9-12 (Piliaris).

[41] Mr. Piliaris, on rebuttal, took exception to Mr. Dittmer's five year analysis of usage per customer, suggesting the time period is too short. Exhibit JAP-5T (Piliaris) at 23-24. However, as Public Counsel points out, he does not disagree with Mr. Dittmer's conclusion that per-customer usage is flat over that period, nor does he provide alternative data that might allow for some alternative inference.

[42] Public Counsel Initial Brief at ¶ 133.

[43] Exhibit JRD-1CT (Dittmer) at 43-44.

[44] PSE Brief at ¶ 74 (footnote omitted).

> On the contrary, nothing is more relevant than the fact that overall loads are increasing, and that usage per electric customer remains flat, in spite of conservation efforts. PSE asks the Commission to employ tunnel vision and look at a single element of customer usage (conservation), while disregarding all other factors that are causing loads to increase. Nothing could be more inconsistent with the requirement of WAC 480-07-510(3)(e)(iii) that offsetting factors must be considered.[45]

Indeed, in response to a hypothetical about a customer who received a rebate for a more efficient gas hot water heater purchased under a PSE conservation program, but also acquired a new gas oven, dryer and cook top at the same time to take advantage of the gas re-plumbing, Mr. Piliaris testified that the net increase in load would not be reflected under the PSE proposal, only the estimated reduced usage for the hot water heater.[46] This illustrates plainly that while a conservation program may lead to reduced load on the one hand, it may stimulate customer behavior that actually increases net load. The net increase in load, which would produce additional margins for PSE, would not be recognized under the Company's conservation phase-in adjustment.

46 Second, PSE's proposed adjustment also fails the known and measurable criteria by which pro forma adjustments are evaluated. The Company argues that conservation in 2007 and 2008 was projected to result in lost margins of $34 million and lost revenues of $46 million.[47] However, PSE provided no support for those amounts, which are misleading, at best.[48] Mr. Piliaris states in his rebuttal that the Blue Ridge

---

[45] Public Counsel Reply Brief at ¶ 30 (citing Avista 2009 GRC Order at ¶¶ 45-47).

[46] Tr. 560:6-561:12 (Piliaris). In response to Bench Request No. 5, PSE clarified that fuel switching effects are not included in the conservation phase-in adjustment because the fuel switching pilot does not begin until after the test year. In the future, however, this issue could re-emerge if the "phase-in" were approved and PSE did not reflect the offsetting effect of increased gas usage.

[47] Exhibit JAP-5T (Piliaris) at 15:5-12.

[48] Tr. 549:20-22 and 552:19-22 (Piliaris). These numbers reflect Mr. Piliaris's calculation of lost margins over a period of several years, not the single year of the test period. Hence, they seriously exaggerate PSE's claim concerning the impact of lost margin during the periods relevant for ratemaking purposes. Furthermore, PSE's lost margin claim fails to consider the effect of intervening rate cases, in which the Company's forecasted load would be reset taking into consideration the impacts of its conservation program. Without considering the effect of resetting the load forecast, the Company could double (or triple)-count conservation's impact on loads.

report "reviewed" and "validated" PSE's conservation savings estimates.[49] However, it is clear from the Blue Ridge report that Blue Ridge performed no "verification" whatever of the estimates or of the data provided by PSE, as acknowledged at hearing in response to questions from the bench.[50] In fact, Blue Ridge suggested that PSE's lack of awareness concerning conservation-related lost revenues and lost margins may indicate "the lack of impact of these disincentives in terms of harm to the financial health of the Company."[51] Furthermore, as Staff points out, there has been no post-installation measurement and verification of PSE's conservation savings claims.[52] While Mr. Piliaris asserts in his rebuttal testimony that PSE's conservation savings estimates are consistent with the International Performance Measurement and Verification Protocol (IPMVP), he was unable, at hearing, to provide any explanation of what this means or why it might be significant.[53]

47 *Commission Determination:* Having fully examined the record on this issue, we find compelling reasons to reject PSE's conservation phase-in adjustment. Measured against familiar principles of ratemaking, the proposal does not pass muster as a proper pro forma adjustment. It plainly fails to take obvious and indisputable offsetting factors into account, thus violating the matching principle. Moreover, the evidence PSE presented to support the adjustment as being known and measurable is simply inadequate to its intended purpose.

48 Although we reject PSE's proposed adjustment as presented in this general rate case, we would be remiss to not comment generally on the subject of conservation. The Commission discussed this subject in considerable detail in its recent Final Order in an Avista Corporation (Avista) general rate case proceeding.[54] This was in the context of the Commission's decision to allow Avista to continue on a permanent basis, albeit with significant modifications, a decoupling mechanism previously implemented on a pilot basis. While we need not repeat the Commission's discussion

---

[49] Mr. Pilaris claim in testimony that no party had questioned the Blue Ridge report was shown at the hearing to be a clear misstatement of fact. Tr. 553:3-536:8; Exhibit JAP-12.

[50] Tr. 550:6-551:13 (Piliaris) (discussing lost margin data calculated by PSE but not confirmed by Blue Ridge); *see also* Exhibit JAP-6 at 3.

[51] Exhibit JAP-6 at 78.

[52] Exhibit MPP-1T (Parvinen) at 16; Exhibit JAP-11.

[53] Exhibit JAP-5T (Piliaris) at 10; Tr. 540:19-542:9.

[54] Avista 2009 GRC Order at ¶289.

here, given that the order was published just three months ago, it is worth reiterating the Commission's conclusion of its general and background discussion, as follows:[55]

> Conservation is one of our cornerstone missions. Consequently, we encourage and support efficiency programs as one of the key objectives in our ratemaking. We have long recognized that conservation is, under almost all circumstances, the least cost energy resource available to a utility and its ratepayers.[56] To further its development, we enable company spending on conservation resources by allowing our utilities to collect all costs associated with their respective conservation programs from ratepayers, subject to an annual reconciliation or "true-up." In addition, we have provided financial incentives for meeting and exceeding conservation targets[57] and have approved pilot programs for the purpose of determining whether mechanisms, such as the one we have before us, would support a "conservation" culture within our regulated utilities.[58] With this in mind, we judge Avista's decoupling mechanism and whether it has effectively increased the utility's efforts to support cost-effective conservation programs for its customers.

49 Accordingly, consistent with our recent *Avista* order, PSE should feel free to propose a mechanism to address possible disincentives to conservation, which would include lost revenues due to reduction in load from implementation of its conservation measures. This could take the form of a decoupling program, an attrition adjustment, or a more traditional pro forma adjustment. If PSE can develop fully, propose, and offer persuasive evidence to support any of the above mechanisms, or an alternative mechanism, to promote conservation, we will carefully consider such a proposal in a future proceeding.[59]

---

[55] *Id.* (Internal citations, *infra,* footnotes 56 – 58).

[56] Cost-effective conservation potentials have been clearly identified for decades. The difficulty is achieving them. Hence, the Commission's consideration of decoupling in this [the Avista] docket.

[57] *WUTC v. PSE*, Dockets UE-060266 & UG-060267, Order 08 (January 5, 2007) at ¶¶ 145-158 (PSE 2007 GRC Order).

[58] *WUTC v. Cascade Corporation*, Docket UG-060256, Order 5 (January 12, 2007) at ¶¶ 67-85; *In Re Petition of Avista Corporation d/b/a Avista Utilities For an Order Authorizing Implementation of a Natural Gas Decoupling Mechanism and to Record Accounting Entries Associated With the Mechanism*, Docket UG-060518, Order 04, Final Order Approving Decoupling Pilot Program (February 1, 2007).

[59] The Commission will initiate a review of conservation incentive mechanisms in spring 2010, by filing a Statement of Inquiry under the Administrative Procedure Act, RCW 34.05.310. We

50 Of course, one possible mechanism is a direct incentive mechanism by which the utility is rewarded for exceeding conservation targets. Such a program is authorized by state law.[60] We approved such an Energy Conservation Incentive Mechanism (ECIM) for PSE on a pilot basis in Docket UE-060266 in 2007.[61] The ECIM provided $3.5 million in additional revenue to the Company during 2007, or 146 percent of the lost margin the Blue Ridge report shows PSE attributes to conservation programs for that year.[62] During the test year, the ECIM provided PSE $4.3 million in additional revenue, making a significant contribution to PSE's test year margin losses that are attributed to its conservation programs during 2008.[63] Given these benefits – and positive incentives – we find it surprising that PSE has elected to abandon its existing opportunity to recover via incentives at least a portion of its costs associated with conservation efforts that might arguably be lost through reduced load resulting from that same conservation. This is particularly unfortunate considering that the alternative the Company proposes in this case was put forth without adequate support to permit a meaningful evaluation, which is a necessary precursor to Commission approval.

b. Miscellaneous Operating Expense (Adjustments 10.14 and 9.09)

51 PSE consolidated several small, unrelated items into one larger Miscellaneous Operating Expense adjustment for both its electric and natural gas results of operations.[64] Staff and Public Counsel initially contested PSE's proposed inclusion of increases in service contract baseline charges from Quanta/Potelco, the Company's principal contractor providing construction-related services for both the electric transmission and gas distribution systems. According to Staff witness Mr. Foisy, PSE included increases in service contract baseline charges using estimated contract

---

anticipate that this will be a productive, informal forum, in which to discuss the pros and cons of all such mechanisms.

[60] RCW 19.285.060(4).

[61] PSE 2007 GRC Order.

[62] Exhibit JAP-6 at 65 (Table 12).

[63] *Id.;* Exhibit MPP-1T (Parvinen) at 17:9-12.

[64] The adjustments include, for example, the costs of the Wire Zone Vegetation Management Program and contractual rent for the Summit Building. Other components move the following expenses below the line: the Company store which sells items with PSE logos to employees; airport and hotel parking; and athletic events expenses. These components of the adjustment are not contested. Exhibit MDF-1T (Foisy) at 4:17-5:6.

amounts.[65] Mr. Foisy stated that as of the date of his testimony, these contracts were not signed and finalized and, therefore, do not meet the test of being known and measurable. Staff proposed that the unadjusted test year amounts for these contract costs be used, instead of what PSE proposed.

52 PSE's contracts with Quanta/Potelco were finalized and executed in December 2009.[66] Staff, for this reason, accepted PSE's proposed adjustments[67] that, the Company says in its brief, actually understate the final costs that PSE will incur pursuant to the final contracts.[68]

53 Public Counsel contests this adjustment, arguing that it should be rejected because it fails to "recognize offsets."[69] In addition, Public Counsel argues, the adjustment does not satisfy the known and measurable criteria because the actual amount was being negotiated during the pendency of this proceeding.[70]

54 *Commission Determination:* December 2009 is nearly a year after the end of the test period. Much can change in a year in terms of the Company's overall costs of operation and it is unquestionably true that the further out we go from the test year the less sure we can be that there are not offsetting factors. Consistent with our general discussion concerning the propriety of pro forma adjustments we determine that PSE's adjustment should not be allowed despite Staff's acquiescence at the briefing stage of this proceeding.

c. Property Tax (Adjustments 10.15 and 9.10)

55 Staff's adjustments for property taxes are based on "PSE's actual tax liability for all property for the 2008 test year, based on the actual, centrally-assessed valuation of the Department of Revenue ("DOR") and the actual levy rates announced by taxing

---

[65] Exhibit MDF-1T (Foisy) at 6:6-12.

[66] PSE Initial Brief at ¶ 106 (citing Tr. 173:12-20 (Valdman)); Staff Initial Brief ¶ 44 (citing Tr. 173:21-174:3 (Valdman)).

[67] Staff Initial Brief at ¶ 44 (citing Exhibit B-3 at Exhibit KHB-2, page 2.21and Exhibit KHB-3, page 3.14).

[68] PSE Initial Brief at ¶ 106.

[69] Public Counsel Initial Brief at ¶ 99.

[70] *Id.* (citing Exhibit JRD-1CT (Dittmer) at 49-50).

districts."[71] Staff contests PSE's proposed adjustments for property taxes because "[t]he Company's adjustments utilize estimated property tax levy rates to be paid in 2009."[72] PSE acknowledges this point, stating:

> 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.[73]

56 Although Mr. Marcelia testifies it is appropriate to use this estimated tax rate, his testimony is not persuasive and, in any event, misses the point.[74] As in the case of our recent decision in Avista, it is appropriate here to rely on the most recent available actual tax assessments, rather than the projections used by the Company.[75] While "[i]t is wholly appropriate to pro form new tax rates and assessments *once they become measurable*,"[76] it is equally inappropriate to pro form taxes based on levy rates that will be determined in the future.

57 Staff illustrates by example in its Initial Brief why this is true:

> The 2009 property tax estimates used by PSE for its adjustment have changed and will continue to change until PSE's actual tax liability is finally determined. PSE's initial forecasted change in property taxes for its electric operations was $2,467,222.77 The forecast later decreased 187 percent to ($2,139,835).[78] Similarly, PSE's projection of property taxes for its gas operations changed from $1,308,384 to $1,620,627, a 24 percent increase.[79] It is wholly inappropriate to pro

---

[71] Staff Initial Brief ¶ 75 (citing Exhibit B-2 at Exhibit KHB-2, page 2.22 and Exhibit KHB-3, page 3.15, Exhibit MRM-9; Tr. 465:7-466:16 and Tr. 519:10-19 (Marcelia)).

[72] Exhibit MDF-1T (Foisy) at 8:8-9.

[73] PSE Initial Brief at ¶ 107.

[74] Exhibit MRM-4T (Marcelia) at 16:3-14.

[75] Avista 2009 GRC Order at ¶154.

[76] *Id. (*emphasis added*).*

[77] Exhibit JHS-10 at 21.

[78] Exhibit B-2 at Attachment C, page 2.22.

[79] Exhibit MJS-9 at 9.10; Exhibit B-2 at Attachment D, page 3.15.

> form estimates of property taxes that have so significantly changed and can be expected to change again.[80]

58 PSE included estimates of property taxes for 2009 in the individual plant adjustments for Hopkins Ridge (Adjustment 10.06),[81] Sumas (Adjustment 10.09),[82] and Whitehorn (Adjustment 10.10)[83] As Staff points out in its Initial Brief, the only difference between PSE and Staff concerning these three adjustments is the treatment of property taxes.[84] Staff's single adjustment on property taxes (Adjustment 10.15) using DOR's centrally-assessed valuation of PSE's property, encompasses these adjustments.

59 *Commission Determination:* We find Staff's property tax adjustment, using test year actual tax rates and DOR centrally assessed values, is appropriate. We reject PSE's proposal to use estimated levy rates that will not be known until sometime later this year and may vary significantly from the Company's estimates.[85] Accordingly, we accept Staff's property tax adjustment 10.15 and, in so doing, resolve the disputed property taxes that are the only contested issues between PSE and Staff with respect to Adjustments 10.06, 10.09, 10.10 and 10.33, and one of the contested issues with respect to Adjustments 10.07 and 10.08.[86]

---

[80] Staff Initial Brief at ¶ 77.

[81] Adjustment 10.06 involves the August 2008 addition of four turbines at Hopkins Ridge.

[82] Adjustment 10.09 involves the addition of the Sumas Cogeneration facility in July 2008.

[83] Adjustment 10.10 involves the purchase of Whitehorn in February 2009.

[84] Staff Initial Brief at ¶ 111 (Noting that a comparison of Exhibits B-2 and B-3 demonstrates that PSE has otherwise accepted Staff's calculation of these adjustments based on actual August 2009 plant balances).

[85] We note the interplay between this issue and PSE's proposed property tax adjustments in connection with several of its production properties. Staff's approach is consistent with how tax assessors throughout the state actually assess and tax utility property on an aggregate basis, not individual property by individual property.

[86] In section II.B.2.e. of this Order, *infra*, we reject Public Counsel's proposed adjustments to liability insurance associated with these individual plants. Taken with our decision here, the effect is to accept Staff's Adjustments 10.06, 10.07, 10.08 10.09, 10.10 and 10.33, except for the disputed rate base in Adjustments 10.07 (Wild Horse Expansion) and 10.08 (Mint Farm), which we discuss separately below.

d. Directors and Officers Insurance (Adjustments 10.17 and 9.12)

60 Staff, through Ms. LaRue, agrees with PSE's D&O insurance for the total Company including PSE's allocations both to its subsidiaries and to its electric and gas operations, but advocates that the costs of D&O insurance should be shared equally between ratepayers and shareholders. Ms. LaRue testifies that:

> D&O Insurance financially protects corporate directors and officers when legal claims are brought against them while performing their corporate duties. D&O Insurance is a necessary cost of doing business and it provides benefits to both ratepayers and shareholders. Ratepayers should bear some of the cost of this insurance, as they benefit from it, but shareholders also benefit from D&O Insurance and should therefore bear some of the costs, as well.[87]

61 Mr. Dittmer for Public Counsel also recommends an equal sharing of the Company's premiums for D&O insurance. He testifies that both groups benefit from the coverage. Ratepayers benefit, according to Mr. Dittmer, because D&O insurance facilitates the retention of competent management. While shareholders also enjoy this benefit, Mr. Dittmer testifies that in his experience "if payments were to be made by the insurance carrier, such payments would most likely be made to aggrieved shareholders for directors' and officers' actions that have caused them some kind of economic harm."[88] Thus, shareholders receive an additional benefit.

62 PSE argues:

> 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.[89] The 50% allocation of premiums to shareholders proposed by Commission Staff and Public Counsel has no foundation and is

---

[87] Exhibit AMCL-1T (LaRue) at 4:7-14.

[88] Exhibit JRD-1CT (Dittmer) at 67:11-13.

[89] *See* Exhibit MJS-12T (Stranik) at 21:1-11.

> inconsistent with the Commission's established treatment of such costs.[90]

63 Staff and Public Counsel, however, both point out that the Commission's recent decision in the Avista rate case "recognized that shareholders benefit from D&O insurance and it is therefore inappropriate to charge customers the full cost."[91] Both argue that while the Commission found that a 90/10 sharing between customers and shareholders was appropriate under the facts of that case, PSE has offered nothing to justify its position that no sharing of these costs is appropriate. Therefore, Staff and Public Counsel argue, the Commission should consider a different sharing proportion here.

64 *Commission Determination:* The Commission determined on the basis of a limited record in the Avista general rate case that "D&O insurance is a benefit that is part of the compensation package offered to attract and retain qualified officers and directors."[92] The Commission said in that proceeding that it made sense to split the costs of insurance in the same manner required for other elements of the directors' and officers' compensation, hence requiring a 90/10 percent sharing as between ratepayers and shareholders. There is no similar evidence in the record of this case.

65 Absent evidence supporting a particular sharing of these costs other than Ms. LaRue's statement that PSE's allocations both to its subsidiaries and to its electric and gas operations seem appropriate, we have no basis in the record that would support an allocation of a portion of PSE's proposed adjustment to shareholders. We accordingly determine that PSE's adjustments should be approved.

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

66 PSE's as-filed case included estimates for property and liability insurance premiums. Mr. Story, for PSE, stated the Company's intention to update these premiums, once actual premiums were known. This apparently was done in discovery prior to the

---

[90] PSE Initial Brief at ¶ 109.

[91] Public Counsel Initial Brief at ¶ 111; Staff Initial Brief at ¶ 78.

[92] Avista 2009 GRC Order.

date for Response testimony in which Staff proposed alternative adjustments based on actual premiums.[93] PSE agreed to Staff's proposed adjustment in its rebuttal case.[94]

67 Public Counsel, however, opposes the 2010 property insurance increases PSE included in its pro forma electric and gas expense adjustments as not being known and measurable. Public Counsel also objects to PSE's proposal to update the estimates with actual premiums. Mr. Dittmer testifies that he believes "it is inappropriate to reflect increases occurring *so far beyond* the end of the historic test year for which there are probable offsets."[95] Public Counsel does not tell us, however, at what point in time after PSE filed its case the actual premiums became known.[96]

68 PSE argues that Public Counsel's "suggestion that there may be hypothetical but unidentified offsets to the actual, known cost of these insurance premiums" is unsupported and therefore an inadequate reason to reject the adjustment, to which Staff and the Company agree.

69 *Commission Determination:* Although we unfortunately do not know the point in time when the actual insurance premiums became known and measurable it apparently was early enough to give Staff time to review them and accept them in its Response Testimony. Public Counsel raises a valid point of principle, as in the case of other pro forma adjustments, but offers no evidence concerning when the actual data became known during the discovery process, or evidence of offsetting changes. Although it is a close call, we find Staff's use of actual data as of the time it filed its response case offers sufficient support for that result to be sustained. Our decision to accept Staff's insurance adjustments, with which PSE agrees, applies to Adjustments 9.16, 10.23,10.06, 10.07, 10.08 10.09, 10.10 and 10.33.[97]

---

[93] Exhibit TES-1T (Schooley) at 6:1-12.

[94] Exhibit JHS-14T (Story) at 23:9-13.

[95] Exhibit JRD-1CT (Dittmer) at 49:17-19; Public Counsel Initial Brief at ¶ 98.

[96] Mr. Schooley refers to PSE's response to Staff Data Request 175 as the source for his adjustment, to which PSE agrees. Exhibit TES-1T (Schooley) at 6:6. That discovery response, however, is not an exhibit in our record.

[97] In section II.B.2.c. of this Order, *supra*, we accept Staff's property tax adjustment 10.15. This, along with our decision here, means that Adjustments 10.06, 10.07, 10.08 10.09, 10.10 and 10.33 are resolved in favor of Staff's adjustments, except for the disputed rate base in Adjustments 10.07 (Wild Horse Expansion) and 10.08 (Mint Farm), which we discuss separately below.

f. Pension Plan (Adjustments 10.24 and 9.17)

70 PSE used a four-year average of pension contributions including projected pension contributions through September 30, 2009, as the basis for its proposed adjustment to pension plan expense. Public Counsel argues that pension expense for PSE's qualified retirement plan should be calculated based upon a four year average of contributions for the four calendar years ending December 2008. FEA advocates using the same period for the determination (*i.e.*, four-year average through December 2008), but recommends using Financial Accounting Standard (FAS) 87 expense levels that are calculated on an actuarial basis, rather than actual contributions. [98]

71 Public Counsel states its approach "is consistent with the methodology employed in PSE's last two rate cases, which included four years of contributions, the last year of which coincided with the end of the then-utilized historic test year."[99] Here, however, Public Counsel argues that:

> PSE departed from its past approach by "reaching" forward to pick up actual/anticipated contributions to be made some nine months following the end of the historic test year being used in this docket. By "reaching" to pick up contributions for the four twelve-month periods ending September 30, 2006, September 30, 2007, September 30, 2008 and September 30, 2009, PSE was effectively able to include in its four-year average one additional "heavy" year of contributions. This is not appropriate. If an average of "contributions" is to be employed to calculate "normalized" pension costs, as in previous PSE rate cases, the methodology and cut-off periods used in the calculation should be applied consistently. PSE should not be allowed to pick and choose the most beneficial annual periods that it desires to include in the normalization calculation.[100]

72 PSE does not dispute that it looked nine months beyond the test year to its planned 2009 contributions when proposing its pension adjustment.

---

[98] Exhibit RCS-1CT (Smith) at 24:11-16.

[99] Public Counsel Initial Brief at ¶ 102 (citing Exhibit JRD-1CT (Dittmer) at 55).

[100] *Id.* at ¶ 103. Notably, PSE did not contribute to its pension fund during 2004-2005 because of plan funding levels. PSE states further that while in 2006 and 2007, the Company could have made tax deductible contributions, it chose not to because the plan was fully funded. PSE Initial Brief at ¶ 112 (citing Exhibit TMH-9CT (Hunt) at 12:7-10).

73 Ignoring its own proposal to change methodology and use estimated amounts, PSE argues somewhat ironically that FEA's proposal to use FAS 87 calculated pension expense instead of actual cash contributions is a "retreat from long-established Commission practice of using actual cash payments to determine rate recovery" and that it therefore should be denied.[101] PSE argues:

> 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.[102]

Such criticism, of course, can equally be leveled at PSE's departure in this case from recent past practice of using a four year average through the end of the test year.

74 Public Counsel and FEA also recommend removing costs for PSE's Supplemental Excess Benefit Retirement Plan (SERP), which provides retirement benefits for certain top executives in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. Mr. Dittmer testifies for Public Counsel that highly paid employees who qualify for SERP are already entitled to "normal" retirement benefits pursuant to the "qualified" retirement plan offered. Moreover he says: "the plan is expensive to offer given that it is not tax efficient like the qualified retirement plan."[103] Mr. Dittmer also points out that other Washington utilities are either no longer offering the benefit or do not seek rate recovery of such costs. Mr. Dittmer says "it is reasonable to question 1) whether it is necessary to offer such plans to a select group of already highly compensated employees, and 2) whether it is reasonable to request ratepayers to pay the cost of such "supplemental" retirement plans."[104]

75 PSE argues that SERP is part of the overall compensation package for the Company's executives, not something that should be viewed in isolation.[105] PSE states that the SERP allows executives to replace income at the same proportions in retirement as

---

[101] PSE Initial Brief at ¶ 113.

[102] *Id.*

[103] Exhibit JRD-1CT (Dittmer) 60:21-61:15.

[104] *Id.*

[105] PSE Initial Brief at ¶ 114 (citing Exhibit TMH-9CT (Hunt) at 22:1-14).

compared to other employees and allows mid-career employees to come to PSE without suffering a decrease to their retirement benefits."[106]

76 Ignoring Public Counsel's argument that no other jurisdictional utility in Washington seeks to recover SERP expenses from ratepayers, PSE takes aim at Public Counsel's and FEA's argument that other jurisdictions have not allowed SERP expenses in revenue requirements. PSE contends this is "irrelevant and without merit" because the Commission "has historically allowed SERP expenses in revenue requirements." However, the only authority PSE cites for this assertion is both incorrectly cited and misleading in substance. Specifically, PSE quotes from the Commission's Order 04 in PacifiCorp's 2006 general rate case (albeit identified in PSE's brief as a PSE general rate case), and argues:

> 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. The Company's SERP meets this test. Taken as part of the overall compensation package, it is reasonable as a common feature of a market competitive pay program in the utility industry. [107]

The referenced so-called test, however, was applied in the context of a dispute over incentive compensation, not retirement benefits.

77 Relevant in this context is Public Counsel's point in its brief that PacifiCorp closed its SERP plan to new participants in 2007.[108] Public Counsel also points out that:

> Cascade Natural Gas has prohibited new participants [in its SERP] since 2003 and has restricted new benefits to existing participants. Avista provides SERP to its senior executives but records the cost below the line and does not seek recovery from ratepayers.[109]

Public Counsel argues that other than "boilerplate recruitment and retention arguments, PSE has not offered a persuasive justification for requiring its customers

---

[106] *Id.*

[107] PSE Initial Brief at ¶ 114 (citing *WUTC v. PSE,* Order 04 at ¶ 128 (April 17, 2006) for the quoted language). The quote actually is taken from *WUTC v. PacifiCorp*, Docket 050684, Order 04 (April 17, 2006).

[108] Public Counsel Initial Brief at ¶108.

[109] *Id.* (citing Exhibit JRD-1CT at 64 (regarding Avista 2009 GRC and citing to Tr. 597:10-11 in that proceeding, of which we take administrative notice)).

to pay SERP costs."[110] In addition to its other arguments, Public Counsel closes with the argument that:

> This expense is particularly unjust and unreasonable at a time when many PSE customers face severe economic challenges and many are losing jobs and potentially retirement benefits of their own.[111]

78 In addition to advocating the use of an actuarial basis for determining pension expense and the removal of SERP costs, FEA recommends that the Commission require PSE to:

> Evaluate whether it should continue to provide defined benefit pension plans.[112] As the recent economic turmoil has demonstrated, a defined benefit plan can require radical increases in funding during periods of poor investment performance. Many other companies have discontinued defined benefit pension plans in favor of other alternatives such as Defined Contribution Plans. Basing a ratemaking allowance for pension costs on plan funding contributions, which are up to utility management and can span a range as wide as $60 million or more, could deter the Company from making reforms to its pension plans that would reduce cost.[113]

79 *Commission Determination:* We find that the actual four year average pension expense ending December 31, 2008, provides a reasonable measure of the amount of pension expense that should be allowed for recovery in rates. This approach has been reliably used in recent cases and it provides at least some degree of normalization with respect to contributions that have tended to be highly variable from year to year. PSE's use of projected 2009 contributions is similar in some respects, but does not satisfy the known and measurable standard.

---

[110] Public Counsel Initial Brief at ¶109.

[111] *Id*. (noting that in *Re Application of Connecticut Natural Gas Corp. for a Rate Increase,* Docket No. 08-12-06, Decision (June 30, 2009), at 144 (Section entitled "Current Economic Conditions"), 274 PUR 4th 345, the Connecticut Dept. of PUC rejected SERP recovery as inappropriate and excessive given the current economic climate).

[112] Exhibit RCS-1T (Smith) at 18-20.

[113] FEA Initial Brief at 12 (citing Exhibit RCS-1T (Smith) at 18-20).

80 We do not find FEA's case for moving to an actuarial basis for measuring this expense sufficiently developed to apply it in this case, but a more fully developed record could convince us to order such a change in a future proceeding. There also is insufficient record upon which to make any determinations concerning FEA's suggestion that PSE should move away entirely from offering a defined benefit form of retirement in favor of other alternatives. We emphasize, however, that we are not by this observation making any determination of principle.

81 As to SERP, we find persuasive the arguments recommending removal of these costs. PSE has failed to provide an adequate justification for continuing to require ratepayers to fund supplemental retirement benefits for a small number of executives who already are highly compensated and entitled to the same levels of qualified retirement plan benefits as other employees, within the limits of what the IRS allows.

g. Wage Increase (Adjustments 10.25 and 9.18)

82 Staff and Public Counsel both initially advocated rejection of union and non-union estimated wage increases that PSE projected would occur during 2010. Ms. Huang, for Staff, testified:

> Potential wage increases beyond the current employee contract expiration dates are not known and measurable. Therefore, Staff adjusts wage increases to March 31, 2010 for non-union employees. Staff also adjusts wages increases to March 31, 2010 for IBEW members and to September 30, 2010 for UA members according to the Company's current contract[s] with those unions.[114]

Mr. Dittmer testified that the Commission should also reject a contractual increase for UA (United Association of Plumbers and Pipefitters) union workers because "the increase did not become effective until October 2009, nine months beyond the end of the test year and fifteen months beyond the mid-point of the 2008 test year."[115]

83 PSE and Staff resolved their differences concerning union wage increases given the Company's agreement to include increases provided in contracts.[116] Thus, Staff now accepts inclusion of the IBEW contractual increase that will be effective from January

---

[114] Exhibit JH-1T (Huang) at 4:19-23.

[115] Exhibit JRD-1CT (Dittmer) at 46:8-22.

[116] Staff Initial Brief at ¶ 80 (citing Exhibit MJS-12T (Stranik) at 26:9-10).

1, 2010 to December 31, 2010. Staff and PSE also agree to include wage increases for UA employees through September 30, 2010, the end of the current UA contract.[117]

84 Staff, however, opposes PSE's adjustment to the extent of amounts included for non-union employee wage increases. Specifically, Staff rejects a three percent increase from March 1, 2010, based on the Company's 2010 budget forecast.[118] Staff argues that such budget estimates are uncertain and, thus, not "known and measurable."[119] Staff points out that the budget was not approved until November 2009, that there are no documents supporting the budgeted wage increase and that the Board has the authority to rescind any budgeted increase. Therefore, Staff argues: "It is inappropriate to pro form budgeted wage increases that the Company is not yet obligated to pay."[120]

85 Mr. Dittmer testified for Public Counsel that he:

> Rejected the IBEW 3.00% wage increase *estimated* to be effective in January 1, 2010, the actual UA wage increase that became effective October 1, 2009, as well as the UA 3.00% wage increase *estimated* to be effective on October 1, 2010. Further, I have rejected all non-union wage increases *estimated* to become effective following the March 1, 2009 actual increase granted.

Public Counsel continues to oppose allowing in this adjustment any of the initially estimated union and non-union wage increases because "estimates are not 'known and measurable' changes."[121] Public Counsel would have us exclude in addition the three percent increase for UA employees that became effective October 2009 because it took effect nine months after the test year and fifteen months beyond the test year's mid-point. Public Counsel argues this is not an appropriate adjustment in that it does not account for offsets "for productivity increases, deflationary trends in materials, or an expectation the PSE should strive to cut costs in this economic environment."[122]

---

[117] *Id.* (citing Exhibit JH-3(Huang) at 4:21-23 and Exhibit MJS-20 (Stranik) at 1).

[118] Exhibit TMH-20.

[119] Staff Initial Brief at ¶ 81 (citing Avista 2009 GRC Order at ¶110).

[120] *Id.* at ¶¶ 82 and 83.

[121] Public Counsel Initial Brief at ¶ 95 (citing Exhibit JRD-1CT (Dittmer) at 45-46 (listing PSE pro forma adjustments from testimony of John Story, and describing those rejected by Public Counsel)).

[122] *Id.*

86 PSE argues all its proposed wage increases are known and measurable. PSE states it contractually committed to the IBEW increases in April 2009 and January 2010, but does not mention the UA increase in January 2010.[123] Mr. Hunt testified that PSE contractually agreed to the January 2010 increase in 2007.[124] As 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.[125]

87 Turning to the question of offsets, PSE argues that "increased productivity does not translate into "offsets" or reduced hours worked as Commission Staff and Public Counsel claim."[126] Instead, PSE argues, the Company reallocates employees to meet new demands such as those placed on the Company by "increased regulations, compliance, and the ongoing work of system replacement."[127]

88 *Commission Determination:* We agree with Public Counsel's proposed adjustments to wages. Although outside the test period, we allow the IBEW April 2009 contractual increase, which does not appear to be in dispute, because it is close enough in time to the end of the test year to limit our concerns about possible offsets. We agree with Public Counsel that the other changes (IBEW and UA in October 2009 and October 2010, and non-union in March 2010) are too remote from the end of the test year to be included without risk of violating the matching principle.

h. Investment Plan (Adjustments 10.26 and 9.19)

89 According to PSE's 401(k) Investment Plan, the Company matches employees' contributions to their individual retirement accounts. In addition, the Company

---

[123] PSE Initial Brief at ¶ 115.

[124] Exhibit TMH-9CT (Hunt) at 25:4-6.

[125] *Id.* (citing Tr. 449:24-450:6 (Hunt)).

[126] PSE Initial Brief at ¶ 116.

[127] *Id.* (citing Exhibit TMH-9CT (Hunt) at 26:13-15; Tr. 191:5-7 (Valdman)).

contributes to each employee's retirement account an amount equal to one percent of each employee's base pay. Thus, the Investment Plan adjustments are tied to the Company's portion of the investment plan expense and simply reflect the additional expense associated with wage increases, discussed above.

90 *Commission Determination:* The parties do not disagree on the methodology for this adjustment. The differences in their adjustment amounts simply reflect their different positions on the wage adjustments, previously discussed. Given our determination of the wage adjustments in the preceding section of this Order, we here adopt the recommendation by Public Counsel.

i. Employee Insurance (Adjustments 10.27 and 9.20)

91 PSE's as-filed adjustments to Employee Insurance were estimates based on a budget forecast. Thus, Ms. Huang testified, they do not meet the Commission's criteria for pro forma adjustment which allows for known and measurable adjustments to test year amounts.[128] Staff used the actual, negotiated Flex Credit amount per employee of 4.75 percent for 2010 to adjust Employee Insurance. Ms. Huang testifies this so-called Flex Credit amount is based on known and measurable changes that are not offset by other factors. Mr. Hunt testifies on rebuttal that PSE agrees with Staff's recommendation to use the actual 4.75 percent change.

92 The difference in the level of adjustments proposed respectively by PSE and Staff now result from the use of different employee counts. Mr. Stranick testifies that when calculating the adjustment for rebuttal the Company updated the employee counts from 2,586 to 2,613. He explains that the original employee counts were based on a system report 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. Because new employees have 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 PSE's Response to Public Council Data Request No. 319 dated August 17, 2009.

93 Staff opposes the use of PSE's updated employee counts because it includes employees hired at the end of the test period, but not eligible until 30 days later.

[128] Exhibit JH-1T (Huang) at 7:8-1.

94 Mr. Dittmer, for Public Counsel, would disallow any increase in PSE's employee benefit flex credits. He argues that the initial 8% increase proposed by PSE was not known and the 4.75 percent rate was negotiated after the filing date of this rate case and will not be a "known" change until January 1, 2010. Mr. Dittmer testifies:

> It is inequitable to reflect an adjustment occurring so far beyond the end of the historic test year when there are expected "offsets" in the form of efficiency gains, deflation for other cost of service components, as well as expected cost containment efforts on behalf of PSE in the current economic environment.[129]

95 *Commission Determination:* PSE's obligation to provide insurance to employees hired in December 2008 matured at the time they accepted employment. Since this was before the end of the test year, we find it appropriate to include these additional 27 hires for purposes of calculating this adjustment. We do not know exactly when the 4.75 percent actual rate became final and, hence, known and measurable, but we do know it was sufficiently in advance of Staff filing its Response Testimony to permit Staff to examine the amount and be satisfied with it. Considering all the evidence, we find it is the best evidence of the rate we should use for making this adjustment.

j. Injuries and Damages

96 Mr. Dittmer testifies for Public Counsel recommending that PSE's injuries and damages expenses be normalized by using a three year average rather than the test year amounts, which he contends are "considerably higher" on the electric side relative to prior years.[130] PSE argues that "Public Counsel has not demonstrated a reasoned basis for changing from the use of historical test year to a three-year average."[131] However, the total Injuries and Damages Expense accruals for claims, and payments of claims in excess of accrual amounts, for electric and gas operations for the last three years were:

---

[129] Exhibit JRD-1CT (Dittmer) at 48:10-14.

[130] Exhibit JRD-1CT (Dittmer) at 50:20-51:17.

[131] PSE Initial Brief at ¶ 136.

Year	Electric Operations Accruals & Payments in Excess of Accruals	Gas Operations Accruals & Payments in Excess of Accruals
2006	$2,475,968	$465,804
2007	2,205,721	473,145
2008 (test year)	3,847,528	769,674

97 Thus, we see an increase of nearly 75 percent on the electric side and 63 percent on the gas side between 2007 and 2008.

98 PSE also argues that

> 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.[132]

However, we do not perceive that Public Counsel is proposing such an approach. Public Counsel observes that PSE offers no testimony as to why the higher test year amount in 2008 relative to 2006 and 2007 should be considered normal. Public Counsel also makes the point that PSE itself uses multi-year averages for other expenses that exhibit significant differences from year to year, such as bad debt expense and pension costs.

99 *Commission Determination:* A spike in costs in a single year of the magnitudes evident here provides a sufficient basis to consider a normalizing adjustment. Absent any evidence from PSE showing the test year level is representative (*i.e.,* normal), we accept Public Counsel's recommendation to normalize this expense using a three year average.

---

[132] *Id.*

3. Contested Adjustments – Non-Rate Base – Electric Only

a. Power Costs (Adjustment 10.03)

100 Disputed power costs are highly significant in this case in terms of dollars. PSE, ICNU and Staff (ICNU/Staff) jointly, and Public Counsel all propose to reduce projected power costs from the test year levels. On a net operating income measurement ICNU/Staff and the Company are more than $18.6 million apart, and Public Counsel and the Company are nearly $3.7 million apart. In terms of revenue requirement, using the conversion factor we approve here, ICNU/Staff would reduce PSE's power costs by approximately $30 million from the level advocated by the Company. Public Counsel would reduce the Company's power costs by approximately $6 million more than PSE. The parties' relative positions are illustrated in Table 3.

TABLE 3

	PSE	**Staff**	**Public Counsel**
NOI (net operating income)	50,909,893	69,513,083	54,597,730
Revenue Requirement	(81,945,931)	(111,890,125)	(87,881,973)

The parties present a number of discrete arguments that, considered together, make this a complex issue. ICNU/Staff sponsor a number of adjustments to input data used in the AURORA power cost model, and propose a number of adjustments to be made outside of the model (*i.e.*, adjustments to the modeled results).[133] Public Counsel also sponsors adjustments to both the model and its results. In addition, ICNU/Staff and Public Counsel advocate changes to the ratemaking treatment for the Tenaska regulatory asset, the net cost of mark-to-market gas hedges, and the treatment of gas fuel costs in the Power Cost Adjustment.

[133] AURORA is the power cost model PSE uses to estimate net power costs within the west-wide grid of utilities. The AURORA model includes fuel costs, plant statistics and costs to buy and sell power. EPIS, Inc. developed and owns the model, which it calls the AURORAxmp Electric Market Model. The Company's web page describes it as "a fundamentals-based model that employs a multi-area, transmission-constrained dispatch logic to simulate real market conditions. Its true economic dispatch captures the dynamics and economics of electricity markets – both short-term (hourly, daily, monthly) and long-term."

101 *Overall Commission Determination:* We discuss individually below the parties' arguments concerning the disputed aspects of the power cost adjustment. First, we examine the disputed adjustments within the AURORA model and then the disputed adjustments outside the AURORA model. In the final analysis, considering our determination of each issue and applying the results of our determinations to reject the Company's proposed conservation phase-in adjustment and to adjust accordingly the production factor, we arrive at NOI $48,587,893, resulting in a revenue requirement reduction of ($78,208,377). That said, we recognize that these final numbers will change at the compliance stage as the Tenaska and March Point disallowances are taken into account, as discussed by PSE's witness, Mr. Mills.[134]

AURORA Adjustments

Hydro Filtering

102 ICNU/Staff propose to apply a quasi-statistical filter to exclude from AURORA the water-years that fall outside of one standard deviation above or below the mean water year in the 50-year record on which PSE relies (*i.e.*, 1929 – 1978).[135] Applying this filter to the 50-year record of data, they remove 9 years that are "above the range" and 11 years that are "below the range." They derive their adjustment to the Company's power cost by rerunning AURORA with these years excluded and comparing the resulting modeled power costs to the Company's modeled costs.[136] The ICNU/Staff proposal reduces the rate year power cost projection by approximately $5.7 million, as compared to PSE's 50 water year AURORA run.

103 ICNU/Staff acknowledge that their proposed filter "is not based on a scientific study of any kind," but assert that that it is nonetheless a "reasonable approach" because it is simple and straightforward.[137] They take pains to emphasize that their approach "is based on assumptions regarding the probability of water conditions, not normalized power supply costs" because the filter is carried out on water years, not the resulting annual power supply costs.[138] According to ICNU, the purpose of the ICNU/Staff'

---

[134] Exhibit DEM-12CT (Mills) at 58:4-60:11.

[135] ICNU/Staff use hydroelectric generation from the Mid-Columbia projects as a proxy for water years. They refer to the Mid-Columbia generation as the "water flow equivalent."

[136]Exhibit JT-1CT (Schoenbeck/Buckley) at 10:25-11:15.

[137] *Id.* at 11:19-12:5.

[138] *Id.* at 9:1-4.

hydro filtering proposal is to eliminate bias in the calculation of projected rate year power costs, saying: "the removal of extreme outlier years from power cost calculations logically *reduces* bias by normalizing the range of water years under consideration."[139]

104 According to ICNU/Staff, the filtering approach they propose is appropriate because it "better aligns the methodology for determining base power costs with a regulatory environment that includes a PCA."[140] They argue that the filter addresses the power supply costs associated with "extreme, or outlier" water years leaving these low probability events to be addressed, should they occur, in the annual PCA review.[141]

105 ICNU/Staff assert that the Commission has favored water filtering adjustments for utilities with PCA mechanisms pointing to several recent rate case settlements and quoting a recent Commission order, as follows:

> If the Company and its customers will share the costs and benefits of unusual power cost extremes, there is no need to include those extreme circumstances in the calculation of normalized power costs, particularly if they are controversial . . . We agree with Staff and PacifiCorp that water filtering is appropriate in the context of a PCAM, but not appropriate if there is no PCAM in place.[142]

ICNU characterizes this statement as a "guiding principle" and argues for the ICNU/Staff that "there should be no question about the propriety of the ICNU/Staff' hydro filtering proposal" since the Commission has approved hydro filtering when some form of PCA mechanism is present and PSE, in fact, has a PCA.[143]

106 The Company disagrees with this characterization arguing that the Commission has endorsed filtering in theory, but never considered it fully in a case where a company has a PCA. The Company argues that the ICNU/Staff have failed to comply with

---

[139] ICNU Initial Brief at ¶ 27.

[140] Exhibit JT-1CT (Schoenbeck/Buckley)at 7:26-27.

[141] *Id.* at 7:26-8:5

[142] *WUTC v. PacifiCorp*, Dockets UE-061546, et al, Order 8 at ¶¶ 88-89 (June 21, 2007).

[143] ICNU Initial Brief at ¶¶ 23, 25.

Commission directives regarding how filtering should be considered in the context of a PCA.[144]

107 PSE, through Mr. Mills and Dr. Dubin, objects to the hydro filtering proposed by the ICNU/Staff. Mr. Mills testifies:

> In theory, rate year power costs should be calculated using agreed upon methodologies and regulatory precedents. The existence of a PCA mechanism is irrelevant when setting base rates. If a PCA mechanism is in place and if the PCA mechanism indeed shifts risk from the shareholders to customers, it is the underlying conditions of the PCA mechanism itself (*i.e.*, sharing bands and procedures) that should be adjusted to more appropriately balance risk between shareholders and customers—not the underlying power costs. The proposal of the ICNU/Staff merely biases projected rate year power costs.[145]

108 Mr. Mills offers a detailed critique of the proposed hydro filtering and support for PSE's use of 50 years of data. He says that in an average year nearly 30 percent of the Company's power generation comes from hydropower resources. According to Mr. Mills, market prices for power tend to be low when hydropower is abundant and high when hydropower is limited and consequently the distribution of power costs is skewed across various hydro conditions.[146] Considering the definition of "outlier water years" proposed by ICNU/Staff, he notes that three poor hydro years experienced in the last seven years would fall in this category and that over this period PSE has absorbed 90 percent of the power costs in excess of normalized power costs through operation of the PCA.[147] Mr. Mills argues that the balance between risk and benefits associated with deviations from baseline power costs should properly be considered in the design of the PCA and its sharing bands. He notes that the Company prepared a study of that issue pursuant to a settlement condition in the 2007 rate case, but received no comments from the parties in response to that study.[148] Referring to the record of the 2004 general rate case, Mr. Mill's says that both Company and Staff experts agreed that at least 50 water years should be used in

---

[144] PSE Reply Brief at ¶ 7.

[145] Exhibit DEM-12CT (Mills) at 33:18-34:4.

[146] *Id.* at 31:21-32:3.

[147] *Id.* at 33:19-35:9.

[148] *Id.* at 35:11 – 37:3.

AURORA to determine base power costs, in contrast to the filtered record of 30 years proposed by the ICNU/Staff in this case.[149]

109 Mr. Mills also points out an error he asserts the ICNU/Staff made in application of their proposal. Mr. Mills testifies that:

> If the Joint Parties had used only PSE's share of Mid-C hydro generation in its hydro filter calculation, the adjustment would have resulted in a $3.0 million reduction to projected rate year power costs, rather than the $4.6 million reduction calculated using the ICNU/Staff' approach.[150]

110 Dr. Dubin, attacks the hydro filtering adjustment from a statistical and analytical perspective. He presents a detailed discussion to support his conclusions that:

> Commission Staff and ICNU propose a methodology to truncate or trim the hydro data used to set power costs for PSE. There exists no statistical or intuitive reason to filter the hydro-generation in the manner suggested by Commission Staff and ICNU--it is neither appropriate nor statistically sound to eliminate twenty of the fifty data points (40 percent) to force data to be "normal." In short, the proposed hydro filtering methodology is inappropriate, and the Commission should reject this adjustment.[151]

111 Directing fire at Dr. Dubin's testimony, ICNU says:

> What [Dr.] Dubin fails to recognize is that the inherent uncertainty in determining resultant *power costs* during the more extreme water years, good or bad, forms the basis for the ICNU/Staff filtering recommendation-not an extensive analysis of the historical water year data itself.[152]

112 ICNU contends in its brief that considering the "fine points of statistical theory is unhelpful and unnecessary."[153]

---

[149] *Id.* at 39:7-15.

[150] Exhibit DEM-12CT (Mills) at 40:15-18.

[151] Exhibit JAD-1T (Dubin) at 3:4-10.

[152] ICNU Brief at ¶ 30.

[153] *Id*.

113 *Commission Determination:* ICNU and Staff are justified in raising the topic of how power cost normalization should be employed in the context of a power cost adjustment mechanism. The Commission examined this issue in some detail in the 2006 PacifiCorp general rate case. Indeed, the Final Order in that case provides some carefully developed direction on the matter. However, Staff and ICNU have overlooked the focus of the Commission's discussion and the key paragraph in that order. The Commission concluded:

> We find that filtering water-years is appropriate in the context of a PCAM, but that such filtering must reflect whether the distribution of variability in power costs is symmetrical or skewed as well as how the deadband and sharing bands are designed to reflect asymmetry in the risks and benefits that may accrue to both customers and the Company.[154]

It is simply not the case that the Commission "favored a water filtering adjustment for utilities with a PCA mechanism." Instead, it found that, if designed correctly, a water filtering mechanism could be appropriate in the context of a PCA mechanism. The Commission did not establish a "guiding principle" that in the presence of a PCA any form of hydro filter would be appropriate. The hydro filter proposed in this case fails to address any of the issues for which the Commission previously gave guidance.[155]

114 Moreover, in the PacifiCorp case cited by ICNU/Staff, the Commission found fault with the specific mechanism proposed here – a simple one-standard-deviation filter. Dr. Dubin's testimony in this case points out persuasively that the filter proposed is not justified on any statistical grounds. ICNU/Staff's assertion that despite its lack of a basis in science, the proposed filter should be adopted because it is simple and

---

[154] *WUTC v. PacifiCorp,* Dockets UE-061546, et al, Order 8 at ¶ 101, June 21, 2007.

[155] In contrast, we note that this matter was addressed in the settlement agreement of Avista's 2008 rate case by adoption of an asymmetric sharing band in that company's Energy Recovery Mechanism. *WUTC v. Avista Corporation,* Order 08, Final Order Approving and Adopting Multi-Party Settlement Stipulation and Requiring Compliance Filing, Dockets UE-080416 and UG-080417 (December 29, 2008) at ¶ 52, Appendix A-Multi-Party Settlement Stipulation at 6-7. The issue was also addressed in the settlement of PSE's 2007 general rate case with a provision requiring the company to complete a study and provide it to the parties by December 2008. *WUTC v. Puget Sound Energy,* Order 12, Final Order Approving And Adopting Settlement Stipulations: Authorizing And Requiring Compliance Filing, Dockets UE-072300 and UG-072301(consolidated) (October 8, 2008), Appendix E-Partial Settlement Re: Electric and Natural Gas Revenue Requirements at ¶ 17.

straightforward is untenable. ICNU/Staff's dismissal of "the fine points of statistical theory" is inapt.

115 Judging from their repeated emphasis that the filter is being applied to water records rather than to the power costs that are correlated with water conditions, ICNU/Staff misread the basic point of our analysis in the PacifiCorp order. Specifically, they miss the point that while hydrologic data may be normally distributed, these data are strongly correlated with power costs which were not normally distributed in the case of PacifiCorp and may not be normally distributed in PSE's case either. Indeed, ICNU acknowledges in its brief that the real focus of the ICNU/Staff proposal is "uncertainty in determining resultant power costs." While it is true that removing both high and low values from the normally distributed water record will not significantly bias the average *water year*, it did, in the case of PacifiCorp, bias the average power cost.[156] Since the purpose of calculating a normalized power cost is to estimate the expected value (*i.e.*, the average) of power costs, the Commission found that the one-standard deviation method was flawed and actually favored a different, less biased, statistical method offered by PacifiCorp in that case.

116 Ultimately, no hydro filter was adopted in the PacifiCorp case because, among other reasons, PacifiCorp does not have a PCA mechanism. But the point of the discussion is what is important here. ICNU/Staff have neither offered any analysis of the probability distribution of power costs nor shown how that distribution is related to the probability distribution of hydrologic data. In addition, they have offered no analysis of how those probability distributions affect the sharing of risks and benefits accomplished by the PCA sharing bands. We find this somewhat puzzling in light of the Company having fulfilled its obligation to complete a study and provide it to the parties under the settlement terms of the 2007 rate case.

117 Consistent with our discussion above and for the reasons stated, we reject the ICNU/Staff proposal to apply a quasi-statistical filter to exclude from AURORA the water-years that fall outside of one standard deviation above or below the mean water year in the 50-year record from 1929 – 1978.

---

[156] Indeed, if simply filtering water-years were enough to address the concerns raised in our PacifiCorp order, there would be no reason to use multiple water years at all. The average water year would suffice. We find value in the using AURORA with a full distribution of water records because the modeled results capture the way the water conditions interact with other factors affecting power costs.

118 Having made our determination on the issue contested by the parties, our discussion above leads us to determine also that it would be appropriate for the parties to examine in PSE's next general rate case, or in another suitable proceeding, the questions whether there are asymmetrical risks in the distribution of power costs that may affect the sharing of risks and benefits accomplished by the PCA sharing bands. It seems particularly appropriate that the Commission should hear more on this question in the future given the Company's 2007 study concerning the balance between risk and benefits associated with deviations from baseline power costs and how it should properly be considered in the design of the PCA and its sharing bands.

Hydrologic Record

119 Public Counsel contests PSE's use of the 50-year water record from 1929 – 1978. Public Counsel's witness, Mr. Norwood, testifies:

> PSE has used the average hydro generation level for the 50-year period 1929-1978 as the basis for its rate year hydro forecast in this case. The Company indicates that it has used this period rather than a more recent period because this approach was recommended by the WUTC Staff in the Company's 2004 general rate case. However, the average annual hydro generation level for the Mid-C hydro contacts for the most recent 50-year period for which information is available (*i.e.,* 1949-1998) is significantly higher than the level experienced during the 1929-1978 period.[157] Given the significant increase reflected in the more recent 50-year average hydro generation data for the Mid-C hydro contracts, I am concerned that using the 1929-1978 period for forecasting PSE's hydro generation levels will result in the under-forecast of rate year hydro generation levels and therefore lead to significant over-recovery of power supply costs by PSE.[158]

120 Mr. Norwood recommends that PSE's rate year hydro generation forecast be revised to reflect the average hydro generation levels over the 50-year period 1949-1998. This recommendation would serve to increase PSE's rate year hydro generation forecast for the Mid-C hydro contracts.[159] To calculate the reduction in rate year

---

[157] Exhibit SN-8C.

[158] Exhibit SN-1HCT (Norwood) at 35:5-17 (internal citation omitted).

[159] Exhibit SN-8C.

energy costs resulting from this adjustment, Mr. Norwood used PSE's forecasted average cost of market energy purchases during the rate year.[160] His recommended adjustment for this issue reduces PSE's originally filed rate year power costs by $6,180,410. [161]

121 Turning to Public Counsel's proposal to use a more recent 50 years of available data (1949-1998), Dr. Dubin, testifies that Public Counsel's proposal advocating a 50-year rolling average for this adjustment is arbitrary, unscientific and without merit:

> As I said in my testimony in the 2004 GRC, the 60-year record would be better to use than the 50-year record and similarly the full 70-year record is preferred to the 60-year record or the 50-year record. I strongly advocate the use of the available 70-year hydro record to determine likely future levels of hydro generation and recommend strongly against the use of a rolling average whether the motivation is that 50 is somehow special (it is not) or whether earlier periods reflect significantly lower mean hydro flows (properly tested they do not). Mr. Norwood's suggestion is another form of filtering wherein he ignores the data and arbitrarily drops the first 20 years of the historical hydro record with no basis other than his "concern" that it is different.[162]

122 Mr. Mills testifies that "simply using a more recent period of data because it creates results favored by Public Counsel is not a valid reason to change the hydro information used to set rates."[163] He states that the Company would be willing to use the full 70 year data set, but has instead used the 1929-1978 data because the AURORA model data files do not include the most recent 20 years of hydro data. According to Mr. Mills, the Company has this more recent data for its Mid-C and western Washington hydro resources, but not for the other regional hydro resources that contribute to market pricing in AURORA. He offers a method that would use the full set of 70 years, but would not fully reflect variation in hydro conditions associated with the non-PSE resources.[164]

---

[160] *Id.*

[161] *Id.*

[162] Exhibit JAD-1T (Dubin) at 32:11-33:1.

[163] Exhibit DEM-12CT (Mills) at 42:6-14.

[164] *Id.* at 42:7-43:21.

123 *Commission Determination:* The Company correctly points to the thorough examination of this matter undertaken in its 2004 rate case. The Commission's discussion in that case examines statistical analyses undertaken by both Company and Staff expert witnesses.[165] Those analyses agree in their conclusion that water-year data are normally distributed and trendless and that the longest period of data was the best to use for purposes of estimating normalized power costs. These analyses also concluded that use of a "rolling average" was statistically flawed. The 50-year record spanning 1929 – 1978 was used in the 2004 rate case because the more recent water-year data was not yet adjusted to reflect actual operation of the hydropower system.

124 In this case we are faced with a similar quandary, the science argues for use of data spanning as long a period as possible, but the most recent 20-years of data available for use in AURORA is apparently incomplete. Inasmuch as the Company has access to at least some of the more recent data, its power cost evidence in future rate proceedings should include consideration of that data. It also should be made available to other parties who may wish to address these issues in future cases.

125 We reject Public Counsel's proposal to eliminate the first 20 years of water records in favor of adding the 1978-1998 data because this data set is not demonstrated to be superior to the earlier records and it is not comprehensive for use in AURORA. However, we have stated above our preference for using the longest span of years possible. We reiterate the direction given by the Commission in PSE's 2004/2005 general rate case encouraging the parties to continue their discussions of this subject and their efforts to develop even more rigorous tools for hydro normalization.

Regional Load Forecast Adjustment

126 The Company's September 28, 2009, Supplemental Filing includes significantly reduced loads for PSE, but does not consider any other regional load reductions. The Company's load forecast for the rate year is lower by 3.9 percent than its original filing, ostensibly because of the recent recession and reduced economic growth.

127 The AURORA power supply model uses regional loads throughout the western United States and Canada for determining market electricity prices for purposes of

[165] *WUTC v. Puget Sound Energy*. Dockets UG-040640, UE-040641, UE-031471, and UE-032043 (consolidated), Order No. 06, ¶¶ 124-131(February 18, 2005).

making balancing sales and purchases. Presumably the economic factors affecting PSE's loads have also affected economic growth and power loads throughout the western United States. ICNU/Staff argue that the Company's failure to adjust all of the load forecasts in AURORA leads to an over-estimate of power costs because the model dispatches higher cost resources to meet the unreduced forecast of western loads.[166]

128 ICNU/Staff recommend an adjustment to the AURORA model inputs assuming no load growth for 2009, 2010 and 2011 for Pacific Northwest loads and the loads of Southern California Edison and Pacific Gas & Electric, which they say taken together represent a significant portion of WECC loads. They characterize their adjustment as conservative considering that PSE's own loads actually declined. According to the ICNU/Staff, this approach still results in a reduction to rate year power costs of approximately $ 1.1 million based on a single average water year AURORA run. When determined in conjunction with the other AURORA related adjustments, the decrease in the rate year power cost projection is $0.83 million.

129 Mr. Mills testifies on rebuttal:

> PSE did not reduce regional loads in the AURORA model. PSE believes that its load reduction would have only a minor impact on the Pacific Northwest aggregate loads because the Pacific Northwest rate year load is about 163,229,598 MWhs, or 18,634 aMWs. Therefore, the reduction in PSE's load is less than 1 percent, or only about 0.57%, of the aggregate regional load. A subsequent run of the AURORA model proved the impact of incorporating the regional load reduction in the AURORA analyses is a reduction of about $0.12 million in projected rate year power costs.[167]

130 Mr. Mills disagrees with the adjustment proposed to AURORA model load inputs because he says "neither PSE nor the ICNU/Staff have developed a methodology to analyze the extent of such impact loads."[168] However, he says that the Company agrees that the same economic trend data that reduced PSE's load forecast may have had an impact on the regional load forecast. Therefore, PSE is willing to accept the $1.1 million reduction to the Company's rate year power costs proposed by the

---

[166] Exhibit JT-1CT (Schoenbeck/Buckley) at 4:22-6:17.

[167] Exhibit DEM-12-CT (Mills) at 26:11-18.

[168] *Id.* at 28:7-16.

ICNU/Staff, but only as an adjustment made to the AURORA power cost results, rather than adjustment to the model inputs.[169]

131 *Commission Determination:* ICNU and Staff have identified an error in the Company's calibration of the AURORA model. An adjustment to the rate year power cost is justified to correct this error. The Company is correct to point out that a proper adjustment to the AURORA load would require detailed knowledge of the load forecasts for all of the model's sub-regions. The Company's agreement to adjust the results of the AURORA model by $1.1 million is a reasonable resolution of this issue.

Out of AURORA Adjustments

Jackson Prairie Storage Capacity

132 PSE acquired a three-year assignment of 6,704 MMBtu/day deliverability and 140,622 MMBtu of Jackson Prairie natural gas storage capacity under a three-year, renewable, asset management arrangement with Cabot Oil & Gas Marketing. Under this agreement, PSE will manage these natural gas assets on behalf of Cabot. The Company will pay tariff rates to Cabot for the storage capacity and gas transport capacity and will retain all value obtained from managing the capacity. According to Mr. Mills, PSE's management of the Cabot assets, including the Jackson Prairie storage capacity, will help ensure the reliable provision of gas supply to customers and power generation facilities, enhance the Company's ability to balance load, improve integration of renewable resources, and facilitate PSE's ability to meet peak-load requirements with gas-fired generation facilities.[170]

133 ICNU/Staff assert that while the Company included in its requested revenue requirements the $415,000 cost of the Cabot asset management arrangement, it did not include quantifiable value associated with the benefits it asserts. According to ICNU/Staff, ratepayers should expect to receive benefits that at least partially mitigate the inclusion of the expense in the determination of the rate year power cost projection. According to ICNU/Staff, when the transaction was presented to the Company's Energy Management Committee on March 19, 2009, the presentation showed a cost of $577,000 per year for the arrangement with an associated value of $806,000 per year. The value included a component related to the benefit associated

[169] *Id.* at 27:18-28:7.

[170] Exhibit DEM-12CT (Mills) at 23:6 – 25:5; Exhibit JT-7C.

with the storage capacity. No such benefit is reflected in the Company's filing in this proceeding. ICNU and Staff recommend a storage benefit be included based on the difference in market prices between the low and high gas cost months multiplied by the associated storage volume of the agreement. Based on PSE's Sumas forward prices, this calculation yields a benefit of $338,000 attributable to this arrangement.[171]

134 PSE opposes the proposed adjustment. Mr. Mills testified that if PSE could use this gas storage to capitalize solely on seasonal price differentials, the adjustment proposed by ICNU/Staff would seem appropriate. He asserts, however, that PSE does not have the opportunity to purchase gas at low summer prices and store it to sell during the higher priced winter months. Mr. Mills reiterates on rebuttal that PSE acquired the Cabot asset management agreement storage for reliability and renewable resource integration management. He states that PSE's rate year power costs accordingly should not include any benefit for the seasonal gas price differences.[172]

135 *Commission Determination:* The Company's objection that it did not acquire control of the additional capacity simply to exercise seasonal arbitrage of gas pricing is persuasive. Nonetheless, if the costs of the Cabot arrangement are to be included in rates, any quantifiable benefits also should be taken into account. The best evidence of the appropriate adjustment is found in Exhibit JT-7C, which includes a presentation made to PSE's Board of Directors. The exhibit shows the net benefit of the arrangement on the power side to be $186,000.[173] That, accordingly, is the adjustment we determine should be made here.

Westcoast Pipeline Capacity

136 The Company has acquired additional Canadian natural gas pipeline capacity on the Westcoast Energy System to allow it access to gas deliveries at the "Station 2" delivery point. It asserts that this capacity will allow it to diversify its delivery points for Canadian-sourced gas so that is not solely dependent on the Sumas hub.[174] The Company secured a rate year "basis differential" between gas sourced at Sumas and gas delivered at Sumas from a single broker quote to estimate the benefit of the additional capacity. Applying this differential to gas volumes estimated to be

---

[171] Exhibit JT-1CT (Schoenbeck/Buckley) at 24:17-25:10.

[172] Exhibit DEM-12CT (Mills) at 26:6-13.

[173] Exhibit JT-7C (ICNU/Staff) at 19.

[174] Exhibit DEM-12CT (Mills) at 28:10 -29:20.

delivered at Station 2, and correcting for a spreadsheet error identified by ICNU, the Company estimates a benefit of $5.7 million reduction in power costs.[175]

137 ICNU/Staff do not question the prudence of the Company's acquisition of the pipeline capacity, but they contend additional "basis price differences" are required to justify the significant annual expense of about $8.7 million.[176] This is because, using PSE's approach to estimating basis gain, there are no estimated basis gains during five months of the rate year. They assert that historical data shows that in every trading day for the last two years, there has been a favorable price differential between Station 2 and Sumas. ICNU/Staff say this makes sense because the cost for transporting gas from Station 2 to Sumas was about 47 cents/MMBTU during the test period. Thus, Staff and ICNU argue, faced with the alternatives of buying gas at Station 2 and transporting it to Sumas versus simply buying the gas at Sumas, PSE needs a savings of at least 47 cents/MMBTU at Station 2 as compared to Sumas. Using this estimation "logic," Staff and ICNU recommend an additional $4.0 million in estimated annual benefits, or a total out-of-AURORA rate year basis gain benefit of $9.7 million, requiring a reduction in that amount to the rate year power cost projection.[177]

138 Mr. Riding disputes that PSE acquired the additional gas pipeline capacity to capture an assumed market price differential between Station 2 and Sumas.[178] In fact, he testifies, "PSE has acquired Westcoast Energy T-South capacity in order to improve the reliability and predictability of supply to its generation portfolio by diversifying supply risks."[179] Mr. Riding testifies that the market price differential between Station 2 and Sumas should be considered for PSE's rate-making purposes, but at the "at the contractable differential, which is best measured by market quotes or actual gas supply contracts, consistent with the pricing for all gas purchases for gas-fired generation."[180] He argues that "historical prices, or price differentials, may or may not have any bearing on future prices; therefore, the appropriate methodology is to

---

[175] Exhibit JT-7C (ICNU/Staff) at 15:22-16:7.

[176] *Id.* at 14:11 – 15:18.

[177] *Id.* at 16:12 – 19:11.

[178] Exhibit RCR-6T (Riding) at 7:12-15.

[179] *Id.* at 7:17-19.

[180] *Id.* at 9:14-16.

consistently apply forward price curves and market quotes that are developed primarily by third-party forecasters or market makers."[181]

139 Mr. Riding also contends that recent volatility in the price of gas makes using historical period prices inappropriate.[182]

140 Mr. Mills states that the ICNU/Staff' method produces a basis benefit that exceeds the cost of the pipeline capacity. Mr. Mills testifies that PSE secured four additional broker quotes for the Station 2 to Sumas price differential. Based on these new brokerage quotes, he says, the basis benefit does not exceed the total cost of the new capacity in any month. Mr. Mills accordingly revises his calculation of basis benefit to include an additional $2.4 million.[183] This increases the benefit to $8.1 million (*i.e.*, $5.7 plus $2.4 million).

141 *Commission Determination:* The ICNU/Staff argument that the Company's reliance on a single broker quote is insufficient to estimate the rate-year basis differential is persuasive. We also find merit in the Company's argument that basis differential should be based on forward market information, as are fuel gas prices. On balance, however, we agree with ICNU/Staff that use of documented price differentials between the two stations is a reliable method to determine the benefit of the basis differential. We acknowledge the Company's observation that the resulting benefit more than offsets the cost of the additional capacity but are puzzled by its assertion that this must represent a flaw in the ICNU/Staff proposal. Indeed, we favor Company actions for which the benefits exceed the costs. Accordingly, we determine that the ICNU/Staff proposal to reflect a basis differential of $9.7 million is appropriate. Our decision results in a $1.6 million reduction in power expense from what the Company included in its final case.

---

[181] *Id.* at 9:16-20.

[182] *Id.* at 10:3-21.

[183] Exhibit DEM-12CT (Mills) at 30:13-31:14.

Mark-to-Market for Gas Hedges

142 The Commission has approved a gas mark-to-market adjustment in PSE's last several general rate cases and power cost only rate proceedings. This post-AURORA adjustment reflects the cost difference between PSE's actual short-term forward gas purchases, which are primarily financial but also physical, and the current forward gas price for the rate period used in the AURORA model. The adjustments approved in proceedings since 2004 have ranged from $4,296,000 to $(5,166,000). In this filing, however, PSE's short-term mark-to-market adjustment is over $45,000,000. The adjustment is substantial for various reasons, including that PSE has extended the forward time period over which it purchases gas and the Company has additional baseload gas-fired generation in its power portfolio with the acquisition of Goldendale and Mint Farm.[184]

143 ICNU/Staff say that while these two factors may make sense and may be reasonable, the Company's proposed adjustment in this proceeding is unreasonable because it has procured "far more gas for its power supply requirements than is necessary or justifiable and at a much higher cost than the current market."[185] According to ICNU/Staff, the Company has contracted for 105 percent of the natural gas projected by AURORA to be needed in the April 2010 to March 2011 rate year. ICNU argues that the Company has conducted the forward gas purchases for wholesale activity not reflected in AURORA and that this is "a thoroughly preventable result for which customers should not be charged."[186] Staff and ICNU contend that because AURORA cannot capture PSE's substantial wholesale market trading, there is a mismatch between purchases and need as reflected in the AURORA projections. [187]

144 ICNU/Staff propose that the volume of PSE's forward gas purchases for each month be capped at 80 percent of the AURORA-projected baseload need for each month of the forecast rate-year period. ICNU argues that "this recognizes that it is prudent for a utility to acquire a portion (20%) of its gas needs at market prices, while hedging the remainder."[188]

---

[184] Exhibit JT-1CT (Schoenbeck/Buckley) at 19:17-20:1.

[185] *Id.* at 20:12-14; ICNU Initial Brief at ¶ 8.

[186] ICNU Initial Brief at ¶ 10.

[187] *Id.* at 20:17-22:7.

[188] ICNU Initial Brief at ¶ 10.

145 PSE argues that the ICNU/Staff proposal to cap purchases at 80 percent of the AURORA-projected baseload need for each month of the forecast rate-year period is arbitrary and would expose PSE and its customers to increased market risk.[189] In contrast, PSE states, "the existing treatment for gas hedges has resulted in a cumulative benefit to customers."[190] PSE states that excluding a certain level of long-term mark-to-market contracts, is not appropriate and ignores approximately $122.1 million in customer benefits over the past decade as these long-term and short-term mark-to-market contracts have been included in the calculation of the power cost baseline rate in each of the recent PSE rate proceedings.[191]

146 PSE points out that no one has objected in several general rate cases, power cost only rate cases, or in response to the Company's PCA compliance reports, to PSE's treatment of these contracts. PSE argues:

> 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.[192]

147 PSE argues that the parties are simply wrong in their assertion that PSE's gas hedges exceed the Company's gas for power needs. The Company cites to evidence introduced by ICNU that shows the Company's actual transacted gas hedges are below its forecast gas needs, as modeled by PSE's risk management system.[193] PSE

---

[189] PSE Initial Brief at ¶ 34.

[190] *Id*.

[191] *Id*. at ¶ 36 (citing Tr. 778:19-23 (Mills); Exhibit DEM-12CT (Mills) at 19:7-13).

[192] *Id.* (citing Mills, Tr. 776:6-10; 777:24-778:20; 779:19-23).

[193] Exhibit DEM-23C.

emphasizes that while it hedged in excess of the AURORA-projected gas for power needs, its actual hedging did not exceed its forecast needs.[194] In sum, PSE argues:

> Short-term fixed-price gas for power and power contracts incurred at the price cut-off date for the rate year represent prudent, known and measurable transactions PSE has entered into and is obligated to pay; they are supported by PSE's hedging program, and have been historically included in rates.
>
> * * *
>
> The Joint Parties' argument to cap mark-to-market transaction at 80% of the AURORA forecast ignores the fact that AURORA is a static modeling tool that provides a snapshot in time.[195] The Joint Parties are well aware that PSE utilizes a comprehensive risk management system—not AURORA—for daily management of the energy portfolio. It makes no sense for PSE to base its hedging on a fixed regulatory model and ignore the actual service requirements of its customers.[196]

148 ICNU/Staff propose an alternative to their recommendation to remove mark-to-market costs from base power rates that the mark-to-market costs be recovered through a separate tariff rider with a sunset date at the end of the rate year on April 1, 2011. Public Counsel also contends that a mark-to-market adjustment of the magnitude present in this case should not be a permanent component of baseline power rates. Mr. Norwood asserts there is no basis for including this adjustment beyond the rate year period. Mr. Norwood recommends that a mark-to-market “credit factor” of $0.00201 per kWh be implemented effective April 1, 2011, which is the date immediately following the end of the rate year in this case. This adjustment would have no impact on the rates proposed in this case, but would affect PSE's power cost charges beyond the rate year period. Mr. Norwood recommends that this mark-to-market credit factor should be implemented only if PSE does not modify its baseline power rate before April 1, 2011.[197]

---

[194] These differences are caused by different input assumptions due to regulatory modeling limitations which, in this case, have caused lower heat rates in AURORA. *See* Exhibit DEM-12CT (Mills) at 19:8-14.

[195] *See* Tr. 750:7 – 751:10 (Mills).

[196] PSE Reply Brief at ¶¶ 2, 5.

[197] Exhibit SN-1HCT (Norwood) at 40:19-41:6.

149 Mr. Story and Mr. Mills, for the Company, oppose the ICNU/Staff and Public Counsel proposals to treat the mark-to-market costs in tariffs separate from base rates. Mr. Mills says that they inaccurately portray the mark-to-market as a one-time significant cost that should not be allowed to be included in base rates past the rate year. He contends that, with a $1 billion power portfolio, there are many costs that could potentially be singled out as "significant" and proposed to be recovered separately. He asserts that PSE's hedging program and its attendant costs and benefits is not a one-time event, but an ongoing effort by the Company to mitigate volatility in its power portfolio. He says that there will always be a mark-to-market adjustment because the market cost of gas will vary from the cost of gas negotiated in the hedging contracts. There will be a gain if forward gas prices increase after the date of the hedging transaction, and there will be a cost if forward gas prices decline.[198]

150 Mr. Story testifies that during and beyond the rate year there will be a new relationship of hedges to market gas costs but there is nothing in this record to indicate what that relationship will be. He says that power costs could be much higher and hedging costs lower, yet the net total power cost could be close to what is currently in rates. He contends that, to re-adjust power costs at the end of the rate year as the Joint Parties and Public Counsel recommend would require all costs to be examined. According to Mr. Story, just removing one item in the power cost forecast is not reasonable or justified.[199]

151 *Commission Determination:* This issue is complex. It highlights the difference between the methods used to set the Company's baseline power rate and the methods the Company uses to manage its day-to-day operations. PSE uses the AURORA model only to set the baseline power rate and project normalized power costs. Fundamentally, AURORA results represent a static projection of power system operation in the rate year that cannot serve as a rigid management plan for actual operations. Accordingly, while AURORA is the benchmark used to set normalized power rates, it has been accepted practice to adjust its results to reflect actual costs that are difficult or impossible to include in the model.

---

[198] Exhibit DEM 12-CT (Mills) at 51:1-22.

[199] Exhibit JHS 14-T (Story) at 18:12-21.

152 The mark-to-market adjustment for gas contracts and hedges has been a relatively uncontroversial example of such an adjustment for many years. In this case we are presented with an adjustment that encompasses the same category of costs that have been regularly included in approved baseline power costs rate, but that is much larger than in the past. We find that the parties proposing to change the way mark-to-market gas hedges are treated in determining power costs have failed to present any convincing reason to do so.

153 The Company is correct to argue the importance of matching all costs, benefits, and other factors when rates are adjusted. And it is disappointing to hear ICNU/Staff and Public Counsel advocate a single issue rate adjustment when they otherwise so vigorously and correctly defend the matching principle. If hedging is an appropriate tactic to manage fuel cost risk, and we think it is, then it is appropriate for the cost of hedges to be included in power cost rates.

154 While it is true that the intrinsic value of hedges will vary with the actual cost of gas, this does not make hedging costs any less known and measurable than the market cost of gas that is an input to the AURORA model. We don't find ICNU's argument for excluding a mark-to-market adjustment on this basis consistent or persuasive.

155 This adjustment has routinely been an element of the power cost calculation and we can see no principled reason to exclude it from rates simply because of its size in this case. We also reject the proposals by Public Counsel and ICNU/Staff to separately track the mark-to-market costs through either a tariff that sunsets or a tariff with a delayed credit.

Operations and Maintenance Expense

156 PSE initially proposed to base its operation and maintenance (O&M) expenses on a five-year forecasted cost analysis.[200] Staff opposes the Company's use of budgeted or forecast figures for plant expenditures and relies instead on historical on normalized expenses over a five-year period for established facilities (*i.e.*, Colstrip 1 and 2, Encogen, Frederickson 1 and 2, Fredonia 1-4, Whitehorn) . For new facilities added during the test year, Staff calculates an annual expense based on January through August 2009 (Mint Farm and Hopkins Ridge Infill), monthly average actual expense from August 2008 through August 2009 (Sumas), or actual construction costs through October 2009 (Wild Horse Expansion). Staff used the monthly average actual

[200] Exhibit JHS-1T (Story) at 15:6-10.

expenditure from March 2007 to August 2009 for Goldendale. Staff included the fixed costs associated with the Baker River Project license and the Vestas turbine maintenance contracts for Hopkins Ridge and Wild Horse.[201]

157 Staff argues that its cost figures are more appropriate for ratemaking than the Company's because forecasts and budgeted costs are "inherently unreliable" and should be rejected in favor of documented historical costs.[202] Based on its review of the maintenance costs and requirements at each individual plant, Staff concludes that the pro forma adjustment for rate year plant operation and maintenance should be $90,026,915 – a reduction of $2,305,723 from the test-year level.[203] In total, this reduction is $506,000 greater than the Company's proposed adjustment which reduces test-year expense by $1,799,720.[204]

158 The Company proposes to treat plant operation and maintenance expenses in three categories:

- O&M costs of less than $2 million would be expensed as they occur.

- Capital costs that are prepaid under maintenance contracts will be capitalized when they occur (and not included in the O&M expense item).

- Maintenance events that are not capital in nature, but are in excess of $2 million would be deferred and included in the next general rate case.

Although PSE does not propose to include any maintenance costs in this third category in this rate case, it proposes that deferred costs that are approved in future rate cases be amortized over five-years with the unamortized balance included in rate base as a regulatory asset.[205] The Company requests that the Commission clarify "that rate recovery for actual major maintenance costs for turbines with and without

---

[201] Staff Initial Brief at ¶ 105.

[202] Staff Brief at ¶ 108.

[203] Exhibit B-3 at (revision to KHB-2) at page 2.10 line 18.

[204] Staff Initial Brief at ¶ 96.

[205] Exhibit JHS-1T (Story) at 14:3-15:5.

maintenance contracts be capitalized and amortized to expense over the estimated period until the next planned major maintenance activity."[206]

159 As to O&M expense for projects less than $2 million per occurrence, the Company states it is willing to use historical data rather than forecast data, but it makes the following modifications to Staff's recommended amounts for each plant.

- For Snoqualmie the Company asserts that fixed payment obligations under its FERC license should be included.[207]

- For Colstrip, the Company argues the rate year costs provided by the plant owner, PPL-Montana, should be used. According to the Company, these costs have been reviewed and approved by the majority of owners and such costs have been included in the last six rate cases.[208]

- For Goldendale, the Company argues that test-year costs should be used because the 30-month average used by Staff does not reflect the period of time the plant was owned by PSE.[209]

- For Mint Farm, the Company proposes to use Goldendale as a proxy. It argues that Staff's January to August data fails to reflect fall and winter operational data.[210]

- For Sumas, the Company proposes to use a full year of data ending October 2009, rather than the year of data ending August 2009, proposed by Staff. The Company argues that its proposed period represents the most current and accurate figure.[211]

- For Whitehorn, Fredonia, Frederickson and Encogen, the Company proposes to use test-year data, because it says these data are the most current and accurate.[212]

---

[206] PSE Initial Brief at ¶ 87.

[207] *Id.* at ¶ 84.

[208] *Id.* at ¶ 86.

[209] *Id.* at ¶ 89.

[210] *Id.* at ¶ 90.

[211] *Id.* at ¶ 91.

[212] *Id.* at ¶ 92.

- For Wild Horse, Hopkins ridge, and Hopkins Ridge Infill, the Company argues that maintenance contract escalation tied to the Consumer Price Index and the Goss Domestic Product Implicit Price Deflator should be allowed recovery in current rates.[213]

160 Staff opposes the Company's proposal to capitalize major plant maintenance expenses through creation of regulatory assets that are amortized over five-years. Staff argues that this approach would require multiple accounting petitions to determine and track for every facility the appropriate maintenance intervals and resulting expense recovery and would include carrying charges that can become excessive over time.[214] According to Staff, the conventional method of recovering major maintenance costs through the "deferral method" and all other maintenance costs as expense when incurred is superior for ratemaking and does not require capitalization.[215]

161 Public Counsel accepts the levels of plant operation and maintenance expense proposed by the Company on rebuttal.[216] With regard to accounting for the recovery of major plant maintenance, Public Counsel advocates use of the "deferral method" and says that the rate decision in this case should address costs to be deferred and considered in a future rate case.[217]

162 *Commission Determination.* While the Company originally proposed to use forecasts and states that it still supports such an approach in principle, it is willing to accept the use of historical data to determine O&M costs in this proceeding. We have discussed elsewhere in this Order the Commission's longstanding preference for using the best and most representative historical data when making pro forma adjustments. This is the most reliable source of information from which to determine known and measurable changes to test year costs. Accordingly, we will use such data here. The question remains, however, as to what historic data we should use. Staff's figures are based on use of a five-year average that the Company argues do not reflect more current expense trends. Public Counsel accepts the Company's rebuttal amounts. O&M is an ongoing expense and there is no evidence that the more recent historic

---

[213] *Id.* at ¶¶ 93-94.

[214] Staff Initial Brief at ¶ 100-101.

[215] *Id.* at ¶ 102.

[216] Public Counsel Initial Brief at ¶ 120.

[217] *Id.* at ¶¶ 121-122.

data upon which the Company would have us rely requires any normalizing adjustments. We accept the Company's proposals and its proposal to reduce overall plant operations and maintenance expense by $1,799,720 from test year levels.

163 All parties advocate that major plaint maintenance should be handled using the "deferral method," though it appears the parties may have some different ideas about what this means in practice. While we accept in principle the use of a deferral methodology for major plant maintenance expenses, we have no need to decide its finer points here. This undoubtedly will be brought before the Commission in some future proceeding when such costs are incurred and it will then be ripe for decision.

Off System Sales

164 Public Counsel witness Norwood recommends that PSE's baseline power cost forecast for the rate year be adjusted outside of AURORA to reflect the average annual volume of off-system power sales (OSS) made by PSE over the last 5 calendar years. He states PSE's level of OSS is much higher than the level projected in the AURORA model.[218] Mr. Norwood testifies that he sees no reasonable explanation for why the modeled level of OSS is so much lower than actual in this case. Moreover, he states, forecast OSS sales have consistently been far below actual sales in recent rate cases. He contends that the actual level of rate year OSS is likely to be even higher than the historical average due to the addition of the Mint Farm and Wild Horse expansion projects.[219] Mr. Norwood argues that if OSS volumes are under-represented in the baseline power rate, that rate may over-recover actual net power costs in the rate.

165 Mr. Norwood recommends that PSE's updated rate year power cost forecast be reduced to reflect a credit of $5,141,295 to account for OSS.[220] In addition, he recommends that in future cases PSE be required to account for actual OSS revenues and margins and present such information to support the reasonableness of forecasted OSS revenues in its power cost forecasts.[221]

---

[218] Exhibit SN-1HCT (Norwood) at 36:16-37:2.

[219] *Id.* at 37:4-38:3.

[220] Exhibit SN-9C.

[221] Exhibit SN-1HCT (Norwood) at 40:2-4.

166 Public Counsel argues that the Company concedes that the baseline power rate would be lower if OSS revenues were adjusted to be higher than projected in AURORA. Public Counsel also argues that the Company concedes that the baseline power rate would be expected to be lower if power purchases are under-estimated by AURORA because power purchases are only transacted when market power is less expensive the Company's own generation.[222]

167 Staff and ICNU do not take a position on Public Counsel's adjustment, except to say that if their recommended adjustment for mark-to-market gas sales is not adopted, the Commission should adopt Public Counsel's adjustment to reflect increased OSS revenue.[223]

168 Mr. Mill's testifies in opposition to Public Counsel's adjustment. He argues that Mr. Norwood's attack is focused on the reliability of AURORA model that has been used to set the Company's power costs in all recent rate cases. He asserts that the history of the PCA shows power cost under-recoveries of \$6.8 million out of \$6.9 billion in actual power costs over six and one-half years and that this refutes any contention that the baseline power rate has been set too high. He says that in the first eleven months of the current PCA period, PSE has under-recovered \$17 million in power costs.[224]

169 Mr. Mill's says that Public Counsel has focused only on the difference between projected and actual OSS, without considering market purchases. According to Mr. Mills, the Company is "short" more often than it is in a long position and AURORA also tends to under-predict market purchases. He provides data to show that over the past six rate cases actual market purchases exceeded forecast purchases and that in aggregate the dollars spent on increased market purchases exceed the dollars received from increased market sales by \$83.1 million.[225] He testifies that the differences between modeled and actual sales and purchases are the consequence of AURORA modeling the resource portfolio available to PSE and that the actual resources that are available always differ from the model's projection due to the Company's "diverse mix of resources with widely differing operating and cost characteristics."[226]

---

[222] Public Counsel Initial Brief at ¶ 78.

[223] ICNU Initial Brief at ¶ 12.

[224] Exhibit DEM-12CT (Mills) at 44:21-46:2.

[225] *Id.* at 46:15-48:2.

[226] *Id.* at 48:5-9.

170 Mr. Mills argues that the Commission should reject Public Counsel's adjustment to rate year OSS and Public Counsel's $2.00/MWh sales margin because it is not based on any relevant actual margin information.[227] According to PSE, Public Counsel's proposed adjustment lacks any sound foundation and should be rejected.[228]

171 Mr. Mills also urges the Commission to reject Public Counsel's recommendation that PSE be required to account for OSS revenues and margins. He says that to do so would require each sale to be identified with a specific resource which would require the Company to "significantly upgrade and modify its systems, which would require costs not planned in this proceeding."[229]

172 *Commission Determination.* Revenue from off-system sales have an undeniable impact on PSE's net cost of power, just as power purchases are an important element of overall power costs. Public Counsel's attention to this issue highlights some of the limitations of the AURORA model. On balance, however, the Company has done a good job explaining why it is difficult to compare the model's results with actual operations within any given year. As a first priority, the model's normalized results are intended to capture the expected value of net power costs. The Company's evidence shows that while the model underestimates both power purchases and power sales, over the past half dozen years deviations from the baseline power rate have not been biased toward over-recovery.

173 At this point, we are satisfied that the process used to set the baseline power costs is providing a reasonable and robust result that is not partial to either the Company or its customers. We caution however, that continued examination of how well the estimation of net power costs compares with actual power costs is important. In that light, we expect the Company to continue to provide such comparative information in its rate case filings and to provide clear and concise explanations of unusual circumstances and anomalies. The data regarding off system sales and purchases and mark-to-market costs from this case are good examples.

174 We find Public Counsel's proposed reduction in power costs to account for OSS is unnecessary to ensure a reliable estimate of net power costs and conclude it should be rejected. Nor will we require additional record-keeping and reporting as Public

---

[227] *Id.* at 48:19-49:7.

[228] PSE Initial Brief at ¶ 46.

[229] Exhibit DEM-12CT (Mills) at 49:10-19.

Counsel proposes. At this juncture it appears this would cause PSE to incur unnecessary expense because there is no demonstrated need for the data.

Tenaska Amortization

175 The rate year net power cost projection includes an annual $38.3 million expense associated with the buy-down of the Tenaska fuel prices as determined in Dockets UE-971619 and UE-031725. This annual amortization is scheduled to end on December 31, 2011. ICNU/Staff recommend that base rates determined in this proceeding be reduced by the revenue requirement reflecting the expiring balance of the Tenaska amortization. They recommend establishing a tariff rider with a class-specific kWh rate sufficient to recover these costs for the duration of the amortization period, but with a sunset, or ending date, of December 31, 2011. According to ICNU/Staff, this would ensure that the costs are removed from customers' rates in a timely manner with the least amount of administrative burden for the Commission and parties.[230]

176 Mr. Story says that the concept is acceptable to PSE with certain modifications. One deficiency he identifies with the ICNU/Staff proposal is that it fails to address the disallowance associated with the Tenaska buy-down. Mr. Story testifies that the disallowance is implemented as a credit of $2.3 million[231] that is also built into power costs. He contends that this amount should be removed from general tariffs at the same time the amortization of the regulatory asset is removed.

177 Mr. Story also testifies that the ICNU/Staff proposal fails to address the increase in amortization of the regulatory asset that occurs in 2011 and the return on the regulatory asset. He explains that what PSE included in the current proceeding for amortization of, and return on, the regulatory asset for the Tenaska buy down is nine months of 2010 amortization and three months of 2011 amortization. According to Mr. Story, the ICNU/Staff proposal should be corrected to collect the remaining 2011 amortization (*i.e.*, "return of"), and return on, the regulatory asset that occurs after March 2011, the end of the rate year. He testifies that the Company does not oppose implementing a tracker tariff, if the ICNU/Staff proposal is corrected to account for

---

[230] *Id.* at 26:16-27:1.

[231] The final amount of the Tenaska buy down disallowance is dependent on the final authorized rate of return. Exhibit DEM-17C shows the methodology used to determine the disallowance.

all of the costs associated with the remaining Tenaska buy down, and if it provides for a true up of the tracker at the end of the rate year.[232]

178 ICNU/Staff agree with the modifications suggested by Mr. Story and recommend that the Commission order all remaining Tenaska amortization costs be excluded from base rates and recovered through a separate tariff scheduled to sunset at the end of 2011.[233]

179 *Commission Determination:* We find the ICNU/Staff proposal has merit and conclude it should be adopted with the modifications suggested by PSE. The ratepayers will benefit from the timely removal of these costs from rates, regardless of the timing of PSE's next general rate case.

180 As a part of its compliance filing, we direct the Company to remove from its revenue requirement used to set base rates all costs and amounts pertaining to amortization of the Tenaska regulatory asset consistent with the method proposed by the Company and agreed to by ICNU/Staff. We direct the Company to file a separate tariff rider for recovery of these costs set to expire once all costs have been recovered.[234]

Gas Trigger Mechanism

181 Public Counsel recommends the Commission consider implementing a mechanism to "trigger" a power cost reduction whenever gas prices drop by 15% or more from the gas prices reflected in the AURORA model.[235] Mr. Norwood states that PSE's gas-fired generation has increased over the past five years, which he says will make fuel costs more volatile and difficult to predict. He contends that a trigger mechanism is appropriate because the Company has little incentive under the PCA to reduce rates when market costs go down.[236] Public Counsel argues that adopting a 15 percent trigger mechanism does not impose an administrative burden on the Company since it

---

[232] Exhibit JHS-14T (Story) at 16:18-17:19; Exhibit JHS-32.

[233] ICNU Initial Brief at ¶ 45 (citing Tr. at 589:18-592:5 (Story)).

[234] Removal of all costs associated with amortization of the Tenaska regulatory asset from general revenue requirement will necessarily involve revisions to a number of pro forma adjustments including, but not limited to, Adjustment 10.03 Power Costs, Adjustment 10.31 Regulatory Assets, and Adjustment 10.37 Production Adjustment.

[235] Exhibit SN-1CT (Norwood) at 42:9-13.

[236] *Id.* at 41:10-16.

was willing to adjust its baseline power cost in this proceeding to reflect a change of only 1 percent in gas prices.[237]

182 Mr. Story, for PSE opposes Mr. Norwood's recommendation, saying that the proposed mechanism is neither reasonable nor justified. He contends that, using the 2007 general rate case as an example, the average gas price set in that proceeding was $8.35. According to Mr. Story, the actual average price of gas through October 2009, which is the end of the rate year from that proceeding, was $3.97, a 53 percent decrease from what was set in rates. Pointing to the PCA summary report for the period ending October 2009, Mr. Story says that the Company nevertheless under-recovered its power costs by $25 million over that period. He maintains that adding the additional under recovery of $8.4 million experienced for the month of November 2009 to the $25 million, the total under- recovery since the gas prices were set in rates represents an under recovery of $33.4 million.

183 Mr. Story states that while the arguments to adjust elements of the power cost mechanism may have a certain superficial appeal, the interactions of the resources used to serve the customers are very complex. He says that this is one of the reasons why all the components of power costs are used in setting the PCA baseline rate and are reviewed together in a PCORC or general rate case. He urges that single issue adjustments for one element of the power cost forecast should be denied by the Commission.

184 *Commission Determination:* While Public Counsel's proposal may indeed have superficial appeal, the need for it is not demonstrated by evidence. It is clear from Mr. Story's testimony that an observed decline in natural gas prices between general rate cases, even one of significant magnitude, does not necessarily mean PSE is over recovering its power costs in rates. Moreover, we continue to experience a period during which PSE and other jurisdictional utilities are filing general rate cases on a regular basis. We expect that to continue and see no reason to entertain any mechanisms that might lead to an unnecessary or premature filing. Accordingly, we reject Public Counsel's recommendation.

---

[237] Public Counsel Initial Brief at ¶ 82.

4. Contested Adjustments—Rate Base—Electric and Natural Gas

a. Net Interest Paid to IRS for SSCM (Adjustments 10.36 and 9.03)

185 These adjustments concern PSE's use of the simplified service cost method (SSCM) of accounting under section 263A of the Internal Revenue Code from 2001 to 2003. The SSCM permits companies to deduct costs related to capitalized labor and overheads that they otherwise would have to capitalize. PSE's use of this method resulted in tax deductions totaling $204 million, for a tax benefit of $71.4 million.

186 After an Internal Revenue Service (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.[238] PSE proposes in this case to recover net interest it paid to the Internal Revenue Service, including carrying costs.

187 Staff recommends that the Commission reject this adjustment. Staff argues that PSE has already been the net beneficiary of the use and subsequent disallowance of the tax method. Any additional recovery, Staff argues, would be a windfall to PSE.[239]

188 Staff argues that PSE benefited for several years as a result of deductions taken through the simplified service cost method, but ratepayers received no benefits until March 2005 when the $72 million tax benefit was used to reduce rate base in a general rate case.[240] Staff says that Mr. Marcelia's testimony that customers received benefits since September 2002, when the deferred tax was recorded, relies upon "ratemaking principles" that support a "theory" that the tax benefits offset other utility-related costs that customers should bear.[241] However, Staff argues, PSE provides no support for its theory or asserted ratemaking principles.[242]

---

[238] *See* Exhibit MRM-1T (Marcelia) at 11:1-13:9; Exhibit MRM-3.

[239] Staff Initial Brief ¶ 89 (citing Exhibit RCM-1T (Martin) at 12:6-16:17; Exhibit RCM-2).

[240] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-040641 and UG-040640, Order 06 (February 18, 2007) at ¶27.

[241] Staff Initial Brief ¶ 91 (citing Exhibit MRM-4T (Marcelia) at 37:16-38:2 and Tr. 462:12-22 (Marcelia)).

[242] *Id.* (citing Exhibit MRM-8). Indeed, PSE does not explicitly make this argument in its brief.

189 Staff also argues that ratepayers have already given back to PSE the benefits they eventually derived from lower rates.[243] When the IRS disallowed all of the tax deductions that gave rise to the rate base reduction, PSE incurred financing costs associated with repayment of the tax benefit. The Commission recognized in PSE's 2005 general rate case the potential repayment of tax benefits with interest if the deductions associated with PSE's accounting method were disallowed:

> We cannot lawfully prejudge future rates. However, we do find it appropriate to recognize in principle that if the IRS successfully challenges in court the adjustment PSE and other utilities have taken, and requires future repayment of the current benefits taken, presumably with interest, PSE should file an accounting petition asking for appropriate treatment of any back taxes and interest assessed.[244]

PSE apparently did not make a filing specifically in response to this invitation until November 2008, which, according to PSE, has not yet been "brought before the Commission."[245] In other proceedings, however, the Commission allowed PSE to defer and accumulate financing costs necessary to repay the disallowed benefits,[246] and subsequently authorized rate recovery of the deferred financing costs.[247]

190 Staff's final argument is that PSE's proposed adjustment departs from the traditional ratemaking treatment of income taxes in which the Commission sets rates by looking at the whole income of a company, rather than the taxability of a single item.[248] Staff argues that PSE fails to justify the "unique" treatment it proposes in this adjustment.

191 *Commission Determination:* We find PSE's proposed adjustment to be unwarranted. Exhibit RCM-2, which the Company did not contest, shows that PSE already has received net benefits of $2,948,780 that were not passed through to ratepayers and

---

[243] Exhibit RCM-2.

[244] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-040641 and UG-040640, Order No. 06 at ¶159 (February 18, 2005).

[245] PSE Initial Brief ¶ 129. Although PSE does not identify this filing in its Initial Brief, it apparently is Docket U-082012. Exhibit MRM-4T (Marcelia) at 35:1-6.

[246] *In the Matter of the Petition of Puget Sound Energy*, Dockets UE-051527 and UG-051528, Order No. 01 (October 26, 2005).

[247] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-060266 and UG-060267, Order No. 08 (January 5, 2007).

[248] Tr. 512:9-24 (Marcelia).

$6,905,776 in financing costs paid by ratepayers, for a total of $9,854,557. Subtracting the claimed net interest plus carrying costs paid to the IRS (*i.e.,* 7,741,418) shows the Company benefits exceed by $2,113,139 the amount required to keep it whole in connection with the SSCM. That is, PSE has been more than fully compensated considering all relevant factors, including interest paid to the IRS.

b. Accumulated Deferred Income Tax Adjustment

192 The Federal Executive Agencies (FEA) argue that PSE's electric and natural gas rates should be adjusted to reflect the implementation of an IRS ruling allowing the Company to adjust its tax accounting method for the treatment of repairs.[249] FEA argues that the effect of the ruling is to allow the Company to defer significant additional income taxes that should be reflected by reducing both electric and natural gas rate base.[250]

193 Mr. Smith testifies for FEA that PSE sought approval from the IRS to implement the accounting change at issue by letter dated December 30, 2008.[251] The Company does not dispute that it made this request and it confirms that the IRS granted permission for the accounting method in late 2009. Apparently, the change is reflected in the Company's 2008 tax return.[252] While the IRS has given its consent for the accounting change, it has not yet audited and accepted PSE's figures or methodology.[253] Nonetheless, FEA argues that the increase in accumulated deferred income taxes (ADIT) is known and measurable and should be reflected as a rate base reduction in this case. FEA contends that the expenditures for repairs that are at issue took place during the test year.[254]

[249] One of FEA's arguments is that the IRS also granted Rocky Mountain Power the authorization for the accounting method at issue and that the Utah Public Service Commission approved a rate base reduction effective for a test-year ending June 30, 2010. FEA Initial Brief at 8 (citing Exhibit MRM-14 at 4-5). However, the Utah Public Service Commission's treatment of Rocky Mountain Power is neither controlling in our jurisdiction nor on point, because that treatment apparently involves a future test-year that will not conclude until June of 2010.

[250] FEA Initial Brief at 9. The actual amounts are classified as confidential under the protective order that governs the use of such information in this proceeding.

[251] Exhibit MRM-15C (Marcelia) at 1; Tr. at 470:6-9, 485:1-12; Exhibit RCS-1T (Smith) at 11.

[252] Tr. at 492 (Marcelia) and Exhibit MRM-14 at 9.

[253] Exhibit RCS-1T (Smith) at 11; Tr. at 487:21-488:5; Exhibit MRM-15C.

[254] FEA Initial Brief at 9.

194 The Company opposes FEA's proposed adjustment. According to PSE, the IRS only granted "limited approval for the Company to adopt the repairs methodology after the close of the test year." The Company points out that the IRS has not yet audited the Company's implementation of the methodology. It asserts that its experience with the IRS disallowance of the simplified service cost method (SSCM) shows why it would be inappropriate for the ADIT adjustment FEA advocates to be implemented in this case.[255] In addition it argues that the adjustment would be one-sided because significant expenditures that occurred after the close of the test-year have not been included in this rate proceeding.

195 *Commission Determination:* The Company has apparently implemented the accounting change allowed by the IRS in its 2008 tax return or an amendment to that return. However, the Company is correct to point out that the lesson of the SSCM issue demonstrates the risks of recognizing IRS-allowed accounting changes before they are audited.

196 Additionally, there is the Company's argument that the permissive tax treatment was not granted until long after the end of the test period. While the Company has definitely sought to include some adjustments in its favor that reflect events as long as 12 months after the close of the test-year, the Commission's principles governing pro forma adjustments, and its decisions in this case, are fashioned to allow such adjustments only in limited circumstances.

197 We accordingly reject FEA's adjustment in this case as an inappropriate pro forma adjustment. The final disposition with the IRS is not known and the tax impact is in any event subsequent to the test-year. Having made this determination for purposes of this proceeding, we note that the Company should implement an increase to ADIT in a future case if the IRS approves its methodology for treatment of repair costs following an audit.

c. Corporate Aircraft

198 Public Counsel argues it is reasonable to examine whether the costs of PSE's corporate aircraft are excessive relative to alternative forms of transportation and to remove costs that are considered excessive, for two principal reasons:

---

[255] PSE Initial Brief at ¶ 130.

- PSE's service territory is entirely within Washington State, primarily on the west side of the Cascades in the I-5 corridor, and at most a few hours drive from company headquarters in Bellevue.

- The approximate average cost *per PSE passenger* is $945 per flight leg or $1,890 per round trip for trips that are generally of short duration.[256]

Public Counsel says Mr. Dittmer determined, using conservatively high level of expense for alternative forms of transportation, that PSE's *excess* costs from its aircraft are approximately $550,000.[257]

199 PSE observes that the costs of its corporate aircraft and aircraft operations have been allowed for recovery in rates since it was purchased in 1986.[258] The Company argues that its 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."[259] PSE argues further that 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."[260]

200 PSE also criticizes Public Counsel's analysis of the costs of alternative transportation because:

> It does not 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.[261]

---

[256] Public Counsel explains in a footnote that Mr. Dittmer's $1,890 estimate for the cost per passenger for round trips was developed by dividing the total company corporate aircraft ownership and operation costs included in the development of the test year cost of service (found in Exhibit JRD-2 and Exhibit JRD-3C) and dividing this total by the number of one-way trips taken by all PSE employees, counsel , agents and other representatives during the test year (found in Dittmer workpaper titled "Aircraft Cost Adjustment") to arrive at an average cost for each "one-way" trip of $945. This amount was doubled based on an assumption that most "one-way trips" during the test year represented one leg of a round trip.

[257] Public Counsel Initial Brief at ¶ 114 (citing Exhibit JRD-1CT (Dittmer) at 74).

[258] PSE Initial Brief at ¶ 135.

[259] PSE Initial Brief at ¶ 135 (citing Exhibit MJS-12T (Stranik) 14:15-11).

[260] *Id.* (citing Exhibit MJS-12T (Stranik) 15:13-18:16).

[261] *Id.* (citing Exhibit MJS-12T (Stranik) 15:13-18:16.

While these may be legitimate criticisms of Mr. Dittmer's analysis, Public Counsel closes its argument with the point that:

> PSE provides no empirical data to show that use of the corporate aircraft is more economical than ordinary commercial travel. While it argues productivity benefits, no study has ever been performed to quantify this factor. . . . PSE officers and senior employees may find it convenient to travel by corporate aircraft, but that is not sufficient justification for asking customers to pay the excess costs of that convenience. This is type of economizing that customers can reasonably expect from PSE in the current economic climate.

Public Counsel argues this is significant because it is, after all, PSE that bears the burden of justifying its costs and the Company's attention should be focused at this time on opportunities to save even relatively small amounts of money to help keep rates reasonable.

201 *Commission Determination:* We find that Mr. Dittmer's analysis challenging PSE's recovery of these costs in rates is not sufficiently rigorous to support a decision to disallow them. His analysis, however, raises a legitimate concern. If PSE continues to seek recovery of the costs of its corporate aircraft in future proceedings, the Commission will require evidence showing the ownership and use of a corporate aircraft is more economical than other forms of travel available to the Company.

5. Contested Adjustments—Rate Base—Electric Only

a. Regulatory Assets and Liabilities (Adjustment 10.31)

202 Staff identifies three components to this adjustment that remain in dispute:

- West Coast Pipeline Capacity Payment
- White River Proceeds
- Colstrip Settlement Payment

West Coast Pipeline Capacity Payment

203 The West Coast Pipeline Capacity Payment relates to a regulatory credit PSE received from FB Energy Canada Corporation. PSE received payment on October 24, 2008, for assumption of the pipeline capacity on November 1, 2009.[262] The payment offsets the cost of the capacity charge, which is a variable cost under the Power Cost Adjustment ("PCA") mechanism. Staff treated the credit as an offset to power-related regulatory assets as of the date PSE received payment.[263]

204 PSE agreed to Staff's proposal through Mr. Story's rebuttal testimony, subject to not having to restate prior period PCA reports and financial impacts in previous periods. Mr. Story testifies that these impacts, instead, should be reflected at the time an order issues in this proceeding.[264]

205 Staff argues, however, that:

> PSE ignores the fact that adjustments to prior PCA periods are addressed by approved procedures. Adjustments for previous PCA periods of $1 million or less (debit or credit) flow through the current month's calculation. Adjustments above $1 million (debit or credit) flow through the recalculation of the prior PCA period. PSE has provided no justification to diverge from these established procedures.[265]

206 PSE does not address this matter in its brief.

207 *Commission Determination:* We accept Staff's adjustment, treating the regulatory credit as an offset to power-related regulatory assets as of October 24, 2008. We see no reason to disturb the established PCA procedures described by Staff and direct that they be followed in connection with this adjustment.

White River Proceeds

208 Public Counsel and Staff reflect in this adjustment a net reduction in the tax ramifications of the sale of the White River assets and water rights to the Cascade Water Alliance. PSE initially assumed that all of the sales proceeds would be taxable and proposed to reflect taxes payable as an offset to proceeds of the sale and an

---

[262] Exhibit RCM-1T (Martin) at 9:15-20.

[263] *Id.* at 10:1-8.

[264] Exhibit JHS-14T (Story) at 48:2-9.

[265] Staff Initial Brief ¶ 126 (citing *In the Matter of the Petition of Puget Sound Energy, Inc*., Docket UE-031389, Order 04, Attachment A, Exhibit A, Section C (January 14, 2004)).

increase in rate base. Mr. Dittmer's testimony, however, showed that there would be an expected tax loss on the transaction which would act as an offset to other taxable income generated by electric operations.[266] PSE, accordingly, removed the tax amounts associated with the White River sale.[267]

209 PSE, however, has not agreed with Public Counsel's position, now also subscribed to by Staff, that there should be an incremental rate base reduction to recognize the probable tax loss, which would translate to a tax receivable not yet recognized by the Company. In other words, Public Counsel and Staff argue the tax receivable should be used to reverse the rate base addition proposed by PSE in the form of a tax payable amount.[268] Although the record clearly reflects that the sale will result in a tax loss and attendant tax receivable, PSE argues in rebuttal that it is inappropriate to consider such tax losses in this proceeding until all of the transactions have occurred.[269]

210 Public Counsel argues that this argument is not persuasive because:

> If it was appropriate for PSE to reflect taxes payable as an offset to proceeds of the sale and an increase in rate base, as originally proposed, it is likewise appropriate to recognize the rate base reduction reflecting the tax receivable now expected to result from the sale.[270]

Staff agrees.[271] Staff also points out that the adjustment it adopts from Public Counsel is consistent with the Commission's order establishing that proceeds from the sale of White River assets and all related costs would be deferred without amortization.[272]

211 *Commission Determination:* We find it reasonable to require PSE to reduce its rate base to reflect the tax receivable expected to result from the sale the White River assets, as proposed by Public Counsel and Staff. Application of the proceeds can be

---

[266] Exhibit JRD-1CT (Dittmer) at 15.

[267] Exhibit MRM-4T (Marcelia) at 3.

[268] Exhibit JRD-1CT (Dittmer) at 15:9-20.

[269] *Id.* PSE Initial Brief at ¶ 118.

[270] Public Counsel Initial Brief at ¶ 128.

[271] Staff Initial Brief at ¶¶ 130 and 131.

[272] *In the Matter of the Petition of Puget Sound Energy, Inc.*, Docket UE-032043, Order 06 at ¶¶251-253 (February 18, 2005).

addressed in the next general rate case after the sale of all assets and surplus property is complete.[273]

Colstrip Settlement Payment

212 PSE proposes to defer and amortize over a five year period the cost incurred from certain Colstrip litigation settled in the 2008 test year. Specifically, 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.[274]

213 Staff argues that the Commission should approve creation of a regulatory asset, as proposed by PSE, "only in unusual or extraordinary circumstances."[275] Staff, calculating that the $8.4 million settlement payment is relatively immaterial, constituting only 0.42 percent of total test year operating expense, argues the amount should be expensed, in accordance with FERC's Uniform System of Accounts and GAAP. Staff states that its approach "recognizes that costs of this nature do occur from time to time and, therefore, should be considered as a cost of business relative to their contribution to total expense."[276]

214 Public Counsel argues that the Commission should deny PSE's proposal to recover any Colstrip litigation expenses from customers because "[t]his litigation expense is an unusual and non-recurring item."[277] Therefore, Public Counsel contends, this litigation expense should be borne by shareholders.

---

[273] *In the Matter* of *the Application of Puget Sound Energy, Inc.*, Docket UE-090399, Order 01 at ¶13 (May 14, 2009).

[274] PSE Initial Brief at ¶ 119 *(citing* Exhibit B-3; PSE's Response to Bench Request No. 3, Adjustment 10.31).

[275] Staff Initial Brief at ¶ 134 (citing *Re Puget Sound Power & Light Co*., Dockets UE-920433, 920499 and 921262, 11th Supp. Order at 53 (September 21, 1993) (rejecting deferred accounting of costs without a Commission order approving same) and *Re Pacific Power & Light Co*., Cause Nos. U-82-12 and U-82-35, 4th Supp. Order at 23-24 (February 1, 1983) (rejecting deferred accounting of expenses into capital accounts to the extent the company failed to achieve its authorized return)).

[276] Staff Initial Brief at ¶ 135.

[277] Public Counsel Initial Brief at ¶ 125.

215 PSE rejoins that 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.

216 *Commission Determination:* We are not persuaded that the costs of the Colstrip litigation should be afforded any extraordinary treatment, either as a regulatory asset or as a non-recurring expense. Indeed, these costs are not out of the ordinary and it is appropriate to treat them as a test period expense, as proposed by Staff.

b. Production Property Adjustment (10.37)

217 The Commission recognizes that while it is reasonable to reduce regulatory lag and avoid the under-recovery of the significant costs associated with the acquisition of production assets and power to meet the load expected during the rate year, it is important in doing so to preserve the matching principle. The method by which the Commission has addressed this problem for PSE for many years is by application of a so-called production factor. The production factor is applied so that power and production-related costs are built into rates at the same unit cost when spread over test year loads as they would be using rate year costs spread over rate year load.[278]

218 The production factor is applied separately to power costs and production-related costs. The effect of the production factor on power costs is embedded in Adjustment 10.03, discussed *supra*, in section II.B.3 of our Order.[279] Adjustment 10.37 the production property adjustment, reflects the application of the production factor only to the production-related costs.

219 The production factor is based on the ratio of the test period normalized delivered load to the rate year delivered load. From the time the production factor adjustment was first adopted in the 1970’s, PSE has been in a growth mode. Now, however, the Company projects a significant reduction in loads during the rate year relative to the test year. The Company’s September 28, 2009, supplemental filing includes a significant reduction in forecasted rate year electric loads of 932,382 MWhs, as

[278] *See* Exhibit JHS-14T (Story) at 14:20-15:7.

[279] Although we do not develop the point here, or in our discussion of power costs, application of the production factor proposed by PSE increases power costs by approximately $17 million.

compared to PSE's initial filing. This represents an approximate 3.9 percent reduction in rate year loads, as compared to the initial filing.[280]

220 Under these conditions, Mr. Parvinen for Staff recommends that the production factor adjustment be eliminated in developing the Company's electric revenue requirement in this proceeding. He testifies that the adjustment shifts the risk of reduced loads from the Company to its customers. This in turn, removes the incentive and obligation of the Company to control costs and mitigate the impacts of reduced loads on its financial performance, according to Mr. Parvinen. It simply proposes to adjust loads to compensate itself for the financial consequences of projected reduced loads and the effects those reductions may have on revenues.[281]

221 Mr. Parvinen says the adjustment was never contemplated to be an attrition offset for projected load reductions due to reduced economic activity. The adjustment, he testifies, was designed as an offset to the pro forma rate base calculation where new production rate base was added outside of the test year to serve increasing loads. Staff says that if the Company believes that there is attrition mismatch between test period revenue, expenses, and rate base, it should have supported the adjustment with an attrition analysis in its direct case. According to Staff, it is improper to use the production property adjustment as a "backdoor" means to a proper attrition analysis.[282] Staff contends that the Company has not provided a rebuttal regarding the underlying rationale of Staff's position.[283]

222 Mr. Story, for the Company, says that the production adjustment does not become an adjustment for positive attrition now anymore than it was an adjustment for negative attrition when load was growing.[284] The Company argues that, 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. PSE asserts the Commission has affirmed the production adjustment,

---

[280] Exhibit DEM-9CT (Mills) at 4:11 and Exhibit DEG-9T (Gaines) at 9:3. The Company's proposed conservation phase-in adjustment also affects the originally filed production factor. Our rejection of that adjustment increases *test-period* load by 119,213 MWh. (*See* Exhibit JHS-23 at 2).

[281] Parvinen, MPP-1T 19:16-19.

[282] Exhibit MPP-1T (Parvinen) at 20:5.

[283] Staff Initial Brief at ¶ 160.

[284] Exhibit JHS-14T (Story) at 16:10-16.

noting the Commission described it as a "well established mechanism" for "adjusting rate year cost to match rate year loads."[285] PSE states its approach does no more than allow for the recovery of the production-related costs the Commission approves for recovery in the rate year.[286]

223 Public Counsel proposes an alternative modification to the Company's production property adjustment that removes the effect of the conservation phase-in adjustment and Public Counsel's other rate base adjustments. Public Counsel does not propose a change to the production property methodology or the projected load reduction.

224 The matter of a production property adjustment was at issue in the recent Avista general rate case proceeding. The Commission's Final Order in that proceeding relates Staff's testimony, as follows:[287]

> Staff asserts that the purpose of the adjustment is to "bring the pro formed rate year costs, on a unit basis, back to the historical test year for proper matching and comparability of all costs used in the revenue requirement determination." Staff says that its method allows the Company to recover its test year costs at rate year loads, which is the objective of this type of adjustment.

In this case, Staff apparently believes that the principles guiding the adjustment only apply if loads are growing and that the Company is not entitled to recover its pro formed test-year costs at rate year loads simply because they are lower, rather than higher relative to the test year. Staff's position is logically inconsistent with its position and the Commission's order from only a few months ago. While the factual context here is distinguishable from the Avista facts, this should not engender a new set of principles.

225 *Commission Determination:* While we have some concerns that PSE's revised load forecast is not consistent with other representations the Company has recently made concerning future load,[288] other parties have not challenged it on this record.

---

[285] PSE Reply Brief, ¶ 27 (citing *Avista 2009 GRC Order* at ¶ 50 (December 22, 2009).

[286] *Id.*

[287] Avista 2009 GRC Order at ¶ 100.

[288] We take administrative notice of PSE's revised load forecast presented with its 2009 IRP in the Company's briefing to the Commission on September 10, 2009. We are concerned and perplexed about the apparent discrepancy between that load forecast for the near-term period, which appears

Therefore, we accept it for purposes of establishing rates in this proceeding. At the same time, the Company's proposed decrease *in test period loads* considering its conservation phase-in adjustment is contested by several parties. As previously discussed, we reject the Company's conservation phase-in proposal and therefore adjust upward the test period loads.

226 The net effect of these adjustments to rate period and test period loads is to increase power cost and costs associated with production rate base by 1.760 percent rather than to reduce those costs by 2.741 percent as was the case in the Company's original filing. The production adjustment now decreases net operating income by $2,740,945 versus an increase of $4,657,230 in the original filing, and increases rate base by $27,799,765 versus a decrease of $43,893,528 in the original filing.[289]

227 Because several of our decisions affect the production rate base and related costs, we direct the Company to recalculate this adjustment to give effect to all of our decisions that bear on calculation of the production adjustment including but not limited to the following: the conservation phase-in adjustment, adjustments 10.07 and 10.08 related to Mint Farm and Wild Horse, adjustments 10.34 and 10.38 related to Mint Farm and Wild Horse deferred costs, adjustment 10.31 related to regulatory assets and liabilities, and the removal of all costs and other amounts pertaining to amortization of the Tenaska regulatory asset that we direct be removed from base rates and collected through a separate tariff as discussed below.[290]

228 We acknowledge that the effect of rejecting the conservation phase-in adjustment is to increase test year loads relative to the loads PSE used to calculate its production factor. This, in turn, increases the production factor and the Company's revenue

---

to indicate positive load growth during the rate year, and the 3.9 percent reduction in load forecast for the rate year in the Company's supplemental filing in this proceeding. We have traditionally placed substantial emphasis on the analysis included in the IRP process, and in particular its load and resource balance, since this provides specific information regarding both the timing and preferred resource mix in the future. In this instance, prior to 2009, we specifically asked the Company to revise its IRP load forecast in light of the economic recession. Since both filings were submitted to us within a short period of time, we would not expect to see such a wide divergence in the load forecasts.

[289] Exhibit JHS-9T (Story) at 8:1-8. We note, as previously discussed, that Adjustment 10.37 only addresses production property rate base and associated costs. It does not address application of the production factor adjustment to net power cost. The effect of the production factor adjustment on net power costs is reflected in the power cost adjustment, number 10.03.

[290] At ¶¶ 177-182.

requirement. There is, however a benefit to customers and to the public interest because PSE's more aggressive 2009 IRP conservation target is supported by recognizing in rates the effect of overall load reduction in the rate year, including conservation, relative to the test year.[291] That is, the production factor adjustment shelters production related costs and power costs, which are a major portion of the Company's costs, from the effects of the decline in sales beyond the test year due to Company sponsored conservation.

c. Wild Horse Expansion Rate Base (Adjustment 10.07)

229 PSE expanded the Wild Horse wind generation facility by adding 22 turbines that went into service on November 9, 2009. The Company initially used its cost analysis of the plant expansion to estimate the impact on rate year costs. PSE updated these estimated costs in its rebuttal filing to reflect different estimates for the final costs of construction and rate year expenses.[292] The Company used forecast capital cost expected by December 2009 to calculate the gross plant values for the Wild Horse Expansion.

230 Staff points out that PSE's revised budget forecasts of plant and rate year costs on rebuttal differed significantly from its original estimates.[293] Specifically, PSE's forecast decreased $5,469,920 (5.3 percent) for plant investment, increased $1,295,256 (5630.1 percent) for wheeling, decreased $82,056 (100.0 percent) for property insurance, and decreased $274,947 (61.4 percent) for property taxes.[294] Staff argues that this "demonstrates that the judgment of management, even if informed through detailed analysis, can result in forecasts that fluctuate, in some cases significantly, in violation of [the] requirements [for pro forma adjustments]."[295]

---

[291] *See* Exhibit DEG-9T (Gaines) at 4:3-11; 8:15-18 ("PSE's third and final major change to the [F2008 load] forecast was an increase of the programmatic conservation to reflect the higher energy efficiency acquisition targets that PSE included in the 2009 IRP.").

[292] Exhibit JHS-14T (Story) at 30:2-8.

[293] Staff Initial Brief at ¶ 113 (citing Exhibit JHS-14T (Story) at 30:6-14).

[294] *Id.* (inviting comparison of Exhibit JHS-10 at 13 to Exhibit B-2 at Attachment C, page 2.14). We discuss and resolve issues related to property insurance and property taxes in other sections of this Order.

[295] *Id.* at ¶ 115.

231 Staff's adjustment substitutes all of PSE's rate year projections with actual plant balances through August 2009.[296] Staff's adjustment also reflects the land value of the project included in the test year and the depreciation calculation reflects the actual in-service date of November 9, 2009.[297]

232 *Commission Determination:* Staff's adjustment, based on actual data, meets the requirements of a pro forma adjustment used in historic test year ratemaking in terms of being known and measurable. PSE's approach, using estimates, does not meet these requirements. Although the data on which Staff relies became known and measurable further out from the end of the test year than would ideally be the case, we are less concerned that this might result in a mismatch of costs and revenues because the assets at issue are generation assets, the benefits of which are matched to a significant degree via the power cost and production factor adjustments. We accept Staff's rate base adjustment for the Wild Horse Expansion project.

d. Mint Farm Rate Base (Adjustment 10.08)

233 PSE acquired Mint Farm, a 311 MW natural gas-fired, combined cycle combustion turbine (CCCT) generation facility located in Longview, Washington, and placed it in service in December 2008. PSE's pro forma adjustment relies on the Company's cost analysis of the plant to estimate the impact of the plant on rate year costs. The Company updated these costs on rebuttal to reflect actual plant balances through October 2009 and trued up the estimates of the final costs of construction and rate year expenses.[298]

234 Staff argues, as in the case of the Wild Horse Expansion project, that PSE's adjustment demonstrates again that projections based on management judgment, even when informed, are an improper basis for ratemaking. This is illustrated, Staff argues, by PSE's revised adjustments on rebuttal that include new estimates of plant additions through December 2009.[299] According to Staff, PSE's revised adjustment decreased $3,922,732 (1.6 percent) for plant including acquisition costs, decreased $401,950 (52.1 percent) for property insurance, decreased $475,252 (36.7 percent) for

---

[296] Exhibit KHB-1TC (Breda) at 28:14-17.

[297] Exhibit B-3 at Exhibit KHB-2, page 2.14.

[298] *See* Exhibit JHS-14T (Story) at 32:18-33:6.

[299] Exhibit No. JHS-14T (Story) at 33:9-11.

property tax, decreased $2,864,717 (4.6 percent) for fuel expense, and decreased $4,148,029 (44.30 percent) for O&M expense.[300]

235 Staff's adjustment substitutes all rate year projections with verified, actual plant balances and expense through August 2009.[301]

236 *Commission Determination:* Staff's rate base adjustment, as in the case of the Wild Horse Expansion project discussed immediately above, is based on actual data. Thus, it is known and measurable. PSE's estimates do not meet these requirements. Staff again measured actual plant balances through August 2009, but our concerns about matching are allayed for the same reasons as discussed in the preceding section of this Order. We accept Staff's rate base adjustment for Mint Farm.

e. Mint Farm and Wild Horse Deferred Costs (Adjustments 10.34 and 10.38)

237 PSE requests approval under RCW 80.80.060(6) to defer the fixed and variable costs of Mint Farm, beginning on the acquisition date of December 5, 2008, and ending with the effective date of new rates in this proceeding. Given our determination elsewhere in this Order that RCW 80.80 applies to Mint Farm, PSE is entitled to defer these costs beginning on December 5, 2008.

238 On October 27, 2009, PSE filed with respect to the Wild Horse expansion project a notice of intent to defer, as permitted by RCW 80.80.060(6). There is no dispute that RCW 80.80 applies to the Wild Horse Expansion project and deferrals began on November 9, 2009, the same day the expansion became operational.[302]

239 Although Staff and PSE both contend that there are two contested issues in common as between Mint Farm and Wild Horse with respect to the treatment of these deferred costs, it appears that there is, in fact, only one: Whether PSE is entitled to recover carrying costs on the deferred costs.

---

[300] Staff Initial Brief at ¶ 117 (inviting comparison of Exhibit B-2 at Attachment C, page 2.15 to Exhibit JHS-10 at 14).

[301] As discussed elsewhere in this Order, Staff included actual premiums for property insurance and actual taxes, removing PSE's estimated property tax. Staff Adjustment 10.15 includes the 2008 actual tax liability for all property. *See* Exhibit KHB-1TC (Breda) at 29:16-22.

[302] Exhibit No. RCM-1T at 17:11-19.

240 PSE argues that it should be allowed to recover carrying costs on the deferral. In support of this contention, PSE relies on an extensive quote from Mr. Story's testimony, as follows:

> 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.[303]

241 The principal weakness of this argument, as Staff points out, is that it tacitly depends on the notion that the right to *defer* costs under RCW 80.80 is tantamount to a right to *recover* instantly the deferred costs. This is belied by the language of the statute itself, which states expressly that the creation of a deferral account "does not by itself determine actual costs of the [resource addition], whether recovery of costs is appropriate, or any other issues decided by the Commission in a general rate case."[304]

242 In addition, as Staff also argues, a portion of Mint Farm fixed costs is return on net rate base consisting of plant balance, accumulated depreciation, and deferred income tax. If carrying costs are allowed, the Company's total return on investment will exceed the allowed net of tax return.

243 Finally, with respect to deferred expenses, we must consider that PSE's rate base includes an allowance for investor-supplied working capital. As Staff says: "This allowance, upon which PSE earns a return, provides the Company with funds to pay

---

[303] Exhibit JHS-14T (Story) at 53:4-17.

[304] RCW 80.80.060(6).

its current obligations while awaiting payment from customers."[305] The Commission allows PSE to earn a return on investor supplied working capital. Thus, according to Staff, no further allowance for carrying costs is appropriate.

244 PSE and Staff also identify and argue the question whether the operation of PCA Exhibit G should be suspended with respect to the treatment of net variable costs included in the deferral amounts. Staff and PSE, however, now agree on the treatment of these costs.[306] We accordingly have no reason to address what apparently is, in the context of this case, no more than a theoretical question concerning the operation of the PCA.

245 There is an additional contested issue with respect to the treatment of Mint Farm deferred costs. PSE argues for a 10-year amortization period. Staff advocates a 15 year amortization period.

246 PSE's argument is based simply on the point that a "ten year amortization period for the Mint Farm deferral is consistent with recent decisions." The example PSE offers is that "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."[307] PSE does not explain how the determination of an appropriate amortization period for storm costs is in any way relevant to the determination of an appropriate amortization period for costs associated with a hard asset that has a remaining life of 25-30 years.[308] Staff argues would be "reasonable to amortize the deferred costs over that period in order to match the depreciation of plant costs." Staff nevertheless proposes to amortize the deferred costs associated with Mint Farm over 15 years, which "accelerates recovery in the Company's favor"[309] relative to what would be the case if costs were recovered over the remaining life of the plant.

247 *Commission Determination:* PSE's deferral accounts for Mint Farm and Wild Horse include the Company's capital costs, return on those capital costs and the operating expenses allowed pursuant to the agreement with Staff concerning the treatment of net variable costs. RCW 80.80 allows the Company to defer these costs but does not

---

[305] Staff Initial Brief at ¶ 150.

[306] Staff Initial Brief at ¶ 140; PSE Initial Brief at ¶ 122.

[307] Exhibit JHS-14T (Story) at 54:18 – 55:1.

[308] Exhibit DN-1HCT (Nightingale) at 16:14-19.

[309] Staff Initial Brief at ¶ 153.

authorize recovery and, indeed, expressly reserves the question of recovery for later determination by the Commission in a general rate case proceeding such as this one. Thus, the statute does not disturb the allocation of risks for recovery of deferred costs. It remains just as it would be if PSE were required to file an accounting petition and obtain our approval to defer these costs. It follows from this that there is no reason to allow PSE to recover yet additional revenue in the form of carrying costs.

248 Staff's proposed 15-year amortization for the Mint Farm deferred costs, tied to the expected life of the assets is reasonable. We determine it should be approved.

f. Baker Hydro Relicensing (Adjustment 10.11)

249 This adjustment relates to the cost of obtaining a new license for the Baker River Project. PSE adopted Staff's adjustment for actual plant additions and related amortization expense through August 2009.[310] The only remaining difference is the basis for federal land use fees.[311] Staff excludes what it characterizes as "PSE's rate year estimate of these costs."[312]

250 PSE argues that the fee for 2010 is known and measurable.[313] Mr. Lane testifies for PSE that the Federal Energy Regulatory Commission (FERC) adopted an updated fee schedule on February 24, 2009, for calculating annual charges for use of federal lands.[314] According to Mr. Lane, FERC's regulations[315] double the U.S. Bureau of Land Management's linear right-of-way fees to establish the annual fees for the use of federal lands for project works other than transmission lines, such as these Baker

---

[310] Exhibit JHS-14T (Story) at 40:3-4.

[311] Exhibit B-3 at KHB-2, page 2.18. Staff corrected the amortization rate and accumulated deferred income tax to conform to the Company's adjustment. *See* Exhibit JHS-14T (Story) at 41:3-20.

[312] Staff Initial Brief at ¶ 120 (citing Exhibit KHB-1TC (Breda) at 32:17).

[313] PSE Initial Brief at ¶ 105 (citing Exhibit KWL-1T (Lane) at 9:6).

[314] Exhibit KWL-1T (Lane) at 8:12-17 (citing *Update of the Federal Energy Regulatory Commission's Fees Schedule for Annual Charges for the Use of Government Lands*¸74 Fed. Reg. 8184 (February 24, 2009) FERC Stats. & Regs. ¶ 31,288 (2009); *see also* Order Denying Rehearing, 129 FERC ¶ 61,095 (October 30, 2009)).

[315] 18 C.F.R. § 11.2(b).

Project federal lands.[316] Mr. Lane testifies further that FERC issued an invoice to PSE for the Baker Project's 2009 annual charges for use of federal lands in the amount of $887,223.64, or 75 percent of the full scheduled rental rate in 2009. He notes that this is a significant increase from the 2008 invoiced amount of $231,252.63. Finally, relying on various government publications, Mr. Lane testifies that while PSE is only required to pay 75 percent of the fee in 2009, the amount in 2010 will be the full 100 percent, or a total fee of $1,109,030.00.[317]

251 *Commission Determination:* We find this a close question because Mr. Lane's testimony for the Company is thorough and well documented. It nevertheless depends on expectations of future events as to which there is no evidence of actual experience. That is, our record does not include an invoice or other evidence finally establishing the fee for PSE's use of federal lands in connection with the Baker River facilities during 2010. Thus, we cannot find the amount is known and measurable. We accept Staff's recommendation resulting in an NOI adjustment of $(855,589).[318]

6. Contested Adjustment—Rate Base—Natural Gas Only

a. Jackson Prairie

252 PSE states that it received a refund of tax and interest previously paid to the Washington State Department of Revenue relating to the expansion of the Jackson Prairie natural gas storage 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."[319] According to Staff, this means PSE reduced the Jackson Prairie rate base by $246,875.[320]

253 Public Counsel proposes to reduce the plant balance of Jackson Prairie by the amount of PSE's one-third share of the refund, $246,875. Staff states in its Initial Brief that it

[316] Exhibit KWL-1T (Lane) at 8:17-21 (citing Order Denying Rehearing, 129 FERC ¶ 61,095, at ¶ 8 (October 30, 2009)).

[317] *Id.* at 9:6-21.

[318] Exhibit B-3 (Revision to Exhibit KHB-2, updating Staff's revenue requirements)

[319] PSE Initial Brief at ¶ 141 (citing Exhibit MRM-4T (Marcelia).

[320] Staff Initial Brief at ¶ 161.

adopts Public Counsel's proposal. Mr. Dittmer offered no rationale for this treatment in his testimony and Public Counsel makes no argument of principle on the point in its Initial Brief.

254 *Commission Determination:* Given the testimony and argument presented, it is difficult to understand what, if anything, actually separates the parties on this issue. Public Counsel's recommendation, adopted by Staff, is to reduce PSE's plant balance (*i.e.*, rate base) by $246,875. Staff states that PSE has already reduced the Jackson Prairie rate base by $246,875. PSE, however, does not expressly confirm that the plant balance it included for Jackson Prairie in its initial filing in this case was reduced by this amount.

255 In any event, we find that the plant balance for Jackson Prairie, which we describe for purposes of ratemaking as "rate base," must exclude the $246,875 refund amount that was previously capitalized.

7. Summary of Electric Revenue Requirement Determination

256 Table 4 summarizes the Commission's determinations with respect to the contested electric adjustments (shaded) and the uncontested adjustments, which we accept without the necessity for detailed discussion. Table 5 shows the Electric Revenue Requirement that we approve for recovery in rates, subject to revision to reflect recalculation of the Tenaska and March Point disallowances affecting the power costs adjustment (10.03) and recalculation of the production property adjustment (10.37) made necessary by our decision concerning Mint Farm, Wild Horse and regulatory assets and liabilities.

/
//
///
////
/////
//////
///////
////////
////////
////////

TABLE 4
Commission Determinations of Restating and Pro Forma Adjustments – Electric

Adjustment	Adj. #		NOI	Rate Base	Rev Reqm't
Temperature Normalization	10.01		(12,235,767)	0	$19,695,019
Revenues and Expenses	10.02		86,639,195	0	(139,456,775)
Power Costs [a]	10.03		48,587,893	0	(78,208,377)
Federal Income Taxes *	10.04		(19,308,575)	0	31,079,601
Tax Benefit of Pro Forma Interest	10.05		522,225	0	(840,587)
Hopkins Ridge Infill	10.06		(204,970)	4,075,268	861,258
Wild Horse Expansion	10.07		(3,289,703)	65,055,430	13,777,107
Mint Farm	10.08		(46,408,534)	217,579,446	103,068,382
Sumas	10.09		(594,207)	8,753,305	2,097,705
Whitehorn	10.10		(2,025,046)	17,953,824	5,600,384
Baker Hydro Relicensing	10.11		(855,589)	31,784,211	5,521,197
Pass-Through Revenues & Expenses	10.12		(640,213)	0	1,030,504
Bad Debts	10.13		1,021,353	0	(1,643,997)
Misc Operating Exp	10.14		1,578,526	0	(2,540,838)
Property Tax	10.15		(883,953)	0	1,422,834
Excise Tax & Filing Fee	10.16		264,096	0	(425,096)
D&O Insurance	10.17		205,413	0	(330,638)
Montana Electric Tax *	10.18		50,981	0	(82,060)
Interest on Customer Deposits	10.19		(61,479)	0	98,958
SFAS 133	10.20		4,899,699	0	(7,886,687)
Rate Case Expense	10.21		380,361	0	(612,239)
Deferred Gains/Losses on Property Sales	10.22		(247,166)	0	397,845
Property & Liability Ins	10.23		(778,678)	0	1,253,381

Pension Plan	10.24		(486,442)	0	782,990
Wage increase	10.25		(1,823,076)	0	2,934,472
Investment Plan	10.26		(86,983)	0	140,010
Employee Ins	10.27		(935,975)	0	1,506,570
Incentive Pay	10.28		1,137,979	0	(1,831,722)
Merger Storm Savings	10.29		568,233	0	(914,643)
Storm Damage	10.30		(6,176,024)	0	9,941,094
Regulatory Assets & Liabilities	10.31		(4,659,619)	(116,363,511)	(7,671,201)
Depreciation Study	10.32		9,109,591	4,554,795	(14,069,189)
Fredonia Power Plant	10.33		(1,051,142)	41,512,955	7,104,396
Amortization of. Mint Farm Def Cost	10.34		(2,377,216)	27,099,835	7,359,701
Fleet Vehicles	10.35		1,272,207	7,448,028	(1,076,706)
Net Interest Paid to IRS	10.36		0	(3,530,928)	(460,362)
Production Adjustment [b]	10.37		(2,740,945)	27,799,765	8,036,426
Wild Horse Deferred Cost	10.38		(1,824,273)	2,747,493	3,294,616
Wild Horse Solar Removal	10.39		113,791	(3,663,687)	(660,832)
Excess Aircraft Costs			0	0	0
Injuries & damages			652,896	0	(1,050,919)

[a] The Power Cost adjustment will require revision to recalculate Tenaska and March Point disallowances and to remove recovery of the Tenaska regulatory asset from base rates. This can be accomplished during the compliance filing phase of this proceeding.

[b] The Production adjustment will require revision during the compliance filing phase of this proceeding to reflect removal of the Tenaska regulatory asset from base rates and our decisions concerning Mint Farm and Wild Horse (*i.e.*, Adjustments 10.07, 10.08, 10.34 and 10.38), and our decision concerning Regulatory Assets and Liabilities (Adjustment 10.31).

* These are so-called fall-out adjustments as to which the parties do not disagree in principle.

TABLE 5
Electric Revenue Requirement

Rate Base	$3,797,019,369
Rate of Return	8.10
NOI Requirement	$307,558,569
Pro Forma NOI	$272,640,632
Operating Income Deficiency	$34,917,937
Conversion Factor	.621262

Gross Revenue Requirement Increase	$ 56,204,849

8. Summary of Natural Gas Revenue Requirement Determination

257 Table 6 summarizes the Commission's determinations with respect to the contested natural gas adjustments (shaded) and the uncontested adjustments, which we accept without the necessity for detailed discussion. Table 7 shows the Natural Gas Revenue Requirement that we approve for recovery in rates.

/
//
///
////
/////
//////

TABLE 6
Commission Determinations -Restating and Pro Forma Adjustments – Natural Gas

Adjustment	Adj. #	NOI	Rate Base	Revenue Requirement
Temperature Normalization	9.01	(8,781,321)	0	14,120,354
Revenues & Expenses	9.02	20,919,189	0	(33,638,031)
Net Interest to IRS for SSCM	9.03	0	(2,443,571)	(318,270)
Federal Income Tax	9.04	1,028,039	0	(1,653,086)
Tax benefit of Pro Forma Interest *	9.05	(8,079,880)	0	12,992,437
Depreciation Study	9.06	(6,218,349)	(3,109,174)	9,594,135
Pass Through Revenue & Expense	9.07	342,920	0	(551,415)
Bad Debts	9.08	454,572	0	(730,951)
Miscellaneous Operating Expense	9.09	894,751	0	(1,438,759)
Property Taxes	9.10	(308,161)	0	495,523
Excise Tax & Filing Fee	9.11	693,130	0	(1,114,552)
D&O Insurance	9.12	142,454	0	(229,066)
Interest on Customer Deposits	9.13	(30,273)	(6,973,756)	(859,638)
Rate Case Expense	9.14	153,958	0	(247,564)
Deferred Gains/Losses on Property Sales	9.15	(313,412)	0	503,966
Property & Liability Insurance	9.16	234,055	0	(376,360)
Pension Plan	9.17	(262,622)	0	422,296
Wage Increase	9.18	(866,475)	0	1,393,291
Investment Plan	9.19	(43,626)	0	70,151
Employee Insurance	9.20	(505,317)	0	812,549
Incentive Pay	9.21	615,785	0	(990,182)
Merger Savings	9.22	311,112	0	(500,268)

Fleet Vehicles	9.23	696,545	4,077,858	(588,911)
Jackson Prairie	9.24	0	(246,875)	(32,155)
Corporate Aircraft Costs		0	0	-
Injuries & Damages		130,086	0	(209,178)

* This is a so-called fall-out adjustments as to which the parties do not disagree in principle.

TABLE 7
Natural Gas Revenue Requirement

Rate Base	$ 1,467,519,444
Rate of Return	8.10%
NOI Requirement	$ 118,869,075
Pro Forma NOI	$ 112,557,361
Operating Income Deficiency	$ 6,311,714
Conversion Factor	0.621891
Gross Revenue Requirement Increase	$ 10,149,229

C. Capital Structure and Cost of Capital

258 PSE's currently authorized rate of return (ROR) is 8.25 percent with a return on equity (ROE) of 10.15 percent and an equity ratio of 46 percent. The Commission set these factors on October 8, 2008, in an order approving and adopting the parties' full settlement in Dockets UE-072300 and UG-072301 (consolidated).[321] In this docket, filed just seven months later, the Company requested an overall ROR of 8.5 percent based on a 10.8 percent ROE and an equity ratio of 48 percent.

259 Table 8 summarizes PSE's currently approved capital structure and cost rates and the recommendations of the Company, Staff and Public Counsel in their respective briefs. Our determinations, discussed in detail below, are shown in Table 9.

[321] *WUTC v. Puget Sound Energy*, Final Order Approving And Adopting Settlement Stipulations: Authorizing And Requiring Compliance Filing, Order 12, Dockets UE-072300 and UG-072301(consolidated) (October 8, 2008) at ¶ 51.

TABLE 8
Capital Structure and Cost of Capital Proposals

	Commission Approved		Company Proposal		Staff Proposal		Public Counsel Proposal	
	Share/Cost		Share/Cost		Share/Cost		Share/Cost	
Equity	46.0	10.15	48.0	10.8	45.0	10.0	43.0	9.50
Long-Term Debt	53.97	6.64	48.05	6.70	51.05	6.48	53.0	6.70
Short-Term Debt[322]	NA	NA	3.95	2.47	3.95	2.47	4.0	2.47
Preferred Stock	.03	8.61	0	0	0	0	0	0
TOTAL ROR	**8.25**		**8.50**		**7.91**		**7.73**	

TABLE 9
Commission Determination of Capital Structure and Cost of Capital

	Share %	Cost %	Weighted Cost %
Equity	46	10 .10	4.65
Long-Term Debt	50.05	6.70	3.35
Short-Term Debt	3.95	2.47	0.10
TOTAL ROR			**8.10**

260 The parties' disputes regarding cost of capital focus on the following three issues:

- Share of Common Equity in the capital structure.
- Cost of long-term debt.
- Cost of Common Equity.

---

[322] *Id.* The Commission-approved cost of capital in Dockets UE-072300/UG-072301 (consolidated) includes debt costs as an average of long-term and short-term debt.

261 Mr. Gaines presents PSE's overall cost of capital case for electric and natural gas.[323] Relying on Dr. Morin's testimony for analysis of the cost of common equity, Mr. Gaines says his recommended capital structure, debt costs, and overall 8.50 percent ROR are appropriate and necessary to maintain the Company's credit rating.[324] Mr. Gaines testifies that, in contrast to the Company's proposal, the cost of capital recommendations made by Staff and Public Counsel are unsupported, flawed in method, and if adopted, would be insufficient to maintain the Company's credit metrics and would likely lead to a credit rating downgrade.[325]

262 Mr. Parcell presents Staff's cost of capital recommendations. Based on his recommended capital structure, re-pricing of the Company's projections for new debt issues, and application of conventional methods that estimate the cost of common equity capital, Mr. Parcell recommends 7.91 percent as an appropriate overall cost of capital for PSE.[326] He contends that changes in the capital markets since PSE's last general rate case justify a 15 basis point reduction in return from the current level because, "capital opportunity costs, as well as interest rates, have generally declined from the time PSE's last return on equity was established by the Commission."[327] Mr. Parcell testifies that his recommended rate of return would provide credit metrics sufficient to maintain PSE's "BBB" corporate credit rating.[328]

263 Staff argues that PSE's currently authorized ROE should be reduced because capital markets have recovered and stabilized from the recent global financial crisis, and the economic recession has reduced the profits and capital costs of all enterprises. Staff argues that PSE's return should be reduced because opportunity costs, as well as interest rates have declined since its ROE was last set.[329] In addition, Staff states that PSE has not demonstrated that it faces a greater construction-related risk than other utilities or any problem obtaining the capital necessary to fund its capital program. Finally, Staff contends that Dr. Morin's evidence by itself demonstrates that the

---

[323] Exhibit DEG-1T (Gaines) at 29:13-30:10.

[324] *Id.* at 30:14 -38:10.

[325] Exhibit DEG-11HCT (Gaines) at 2:1-6, 3:19-20:6.

[326] Exhibit DCP-1T (Parcell) at 3:19 – 4:22.

[327] *Id.* at 7:21-24.

[328] *Id.* at 46:1-5.

[329] Staff Initial Brief at ¶¶ 16-20.

Company's cost of capital is declining, because his estimates of ROE dropped during the pendency of this proceeding.[330]

264 Based on the Company's "per books" rate base, the difference between Staff's recommended ROR and the Company's requested ROR is $32.8 million in annual electric revenue and $14.0 million in annual natural gas revenue.

265 Public Counsel presents its overall cost of capital recommendation for electric and natural gas operations through Mr. Hill. Based on his recommended capital structure and return on equity, Mr. Hill recommends an overall rate of return of 7.73 percent. He says that this rate of return will afford the Company an opportunity to achieve a pre-tax interest coverage ratio of 2.72 percent, "well above the interest coverage achieved by PSE in the past five years and sufficient for the Company to maintain its financial position."[331] Mr. Hill testifies that during the financial crisis of late 2008 and early 2009 corporate bond yields increased dramatically, as did the difference between corporate bond yields and the yield on U.S. Treasury bonds (the yield spread).[332] However, he says that since the first quarter of 2009 the risk-free rate as measured by Treasury bond yields has remained low and even declined from pre-crisis levels and that corporate bond yields have declined to below pre-crisis levels. Mr. Hill testifies that the capital markets stabilized during 2009.[333] With this analysis he implies, but does not specifically state, that the cost of capital for a utility like PSE has declined, too.[334]

266 Public Counsel states that once Dr. Morin corrected his DCF, CAPM and Risk Premium analytic estimates of ROE to remove flotation they averaged 10.21 percent, which is considerably below PSE's requested 10.8 percent.[335] He also argues that the Company's assertions that it requires a higher return on capital in order to attract the investment necessary to support its capital program is not credible given that these are

---

[330] *Id.* at ¶¶ 25-26 ("Dr. Morin's original cost of equity was in the upper portion of a range of 11.0 to 11.5 percent. Exhibit No. RAM-1T at 3:11-20. His rebuttal recommendation, however, appeared to be 10.95 percent, but actually had dropped to 10.7 percent. Tr. 654:6-9 (Morin).").

[331] Exhibit SGH-1HCT (Hill) at 5:11-6:3.

[332] *Id.* at 24:6-25:5.

[333] Tr. at 724:15-725:24.

[334] Exhibit SGH-1HCT (Hill) at 25:6-26:3.

[335] Public Counsel Initial Brief at ¶ 24.

the same challenges the Company argued would be addressed by the access to capital provided by the Puget Holdings transaction.[336]

267 Based on the Company's "per books" rate base, the difference between Public Counsel's recommended ROR and the Company's requested ROR is $42.4 million in annual electric revenue and $18.0 million in annual natural gas revenue.

1. Capital Structure

268 No party proposes to base capital structure for purposes of setting rates on the Company's *actual* test-period capital structure or any other measurement of the Company's actual capitalization. PSE, Staff and Public Counsel each propose a different *hypothetical* capital structure. PSE requests a 48 percent equity ratio. Staff recommends 45 percent and Public Counsel proposes 43 percent for the equity ratio.

269 Mr. Gaines testifies that the Company's capital structure during the test year included 44.67 percent equity, but he states this does not reflect the Company's current capital structure because, among other reasons:[337]

- The completion of the transaction to merge Puget Energy with Puget Holdings on February 6, 2009, included investment of funds into PSE used to repay short-term debt and increase PSE equity capitalization.

- PSE defeased and called for redemption of its outstanding preferred stock on March 13, 2009.

- PSE issued $250 million of new 6.75 percent 7-year senior secured notes in January 2009.

---

[336] *Id.* at ¶ 26 ("Puget and the Investor Consortium argued that the transaction offered it the opportunity to meet its capital expenditure requirements, very large relative to its size, through access to a significant pool of "patient capital," providing PSE a "more reliable method of obtaining needed capital now and in the future on reasonable terms without being subject to the vagaries of quarterly and annual earnings forecasts and short-term market reactions." *In the Matter of the Joint Application of Puget Holdings LLC and Puget Sound Energy*, Docket U-072375, Order 08 (December 30, 2008) at ¶ 142); *Id.* at ¶¶ 27-30.

[337] Exhibit DEG-1T (Gaines) at 10:3-11:17.

270 Mr. Gaines says that at the end of the first quarter of 2009, PSE's capital structure included 52.9 percent equity. He testifies, however, that this level of equity capitalization fails to represent the capital structure likely to support utility operations during the rate year. He offers several reasons explaining why this is so, including that some of the Company's long-term debt will mature and be refinanced, Puget Energy will make equity investments in PSE, and the level of outstanding short-term debt and retained earnings will vary.[338]

271 Instead of using the test year capital structure or the actual capital structure at the completion of the merger transaction, Mr. Gaines recommends capitalization that includes 48 percent equity, 48.05 percent long-term debt, and 3.95 percent short-term debt. He says such a capital structure "will allow PSE to attract debt capital necessary to fund PSE's infrastructure and new resource construction program" and that it "appropriately balances the risks and costs of funding PSE's utility operations."[339] Mr. Gaines testifies that a 48 percent equity ratio is comparable to, but lower than, the 49 percent average for equity ratios approved by regulatory bodies in the United States during 2008 and the first quarter of 2009, and the 3.95 percentage of short-term debt is the mid-point of the 3 to 5 percent range of short-term debt PSE expects to use during the rate year.[340] Finally, Mr. Gaines testifies that Standard & Poor's and Moody's assign stable credit ratings to PSE in the BBB and Baa3 categories, respectively, and that the Company's proposed capital structure will support these ratings.[341]

272 Staff presents its capital structure recommendation through Mr. Parcell. He recommends a capital structure containing 45 percent equity based on his review of the Company's actual capital structure for the years 2004 through 2008 and his review of average capital structures allowed by regulatory bodies across the nation for the years 2004 through 2008. Mr. Parcell contends that these data justify an equity ratio of 45 percent because this is "the same capital structure ratio requested by PSE in prior cases" and "is similar to recent actual ratios and is consistent with the capital structures of other utilities."[342] He says that the equity ratio requested by PSE exceeds what was requested by the Company or approved by the Commission in

---

[338] *Id.* at 11:20-13:1.

[339] *Id.* at 12:2-13:19.

[340] *Id.* at 16:4-13 and 22:16:23:1; Exhibit DEG-4.

[341] *Id.* at 32:2-38:10.

[342] Exhibit DCP-1T (Parcell) at 23:13-26:7.

recent proceedings, including the currently approved 46 percent. Staff argues that, in fact, PSE has advocated for a 45 percent equity ratio in its last 5 rate cases despite actual equity ratios that were below 45 percent. Mr. Parcell asserts that PSE's actual capital structure since the conclusion of the merger "reflects decisions made by the new owners of PSE" and "may not be consistent with the Commission's policy to balance safety and economy."[343]

273 Public Counsel presents its capital structure recommendation through Mr. Hill. Mr. Hill states that PSE was able to maintain a BBB corporate credit rating from December 2004 to December 2008 with an actual equity ratio of only 41.71 percent.[344] He testifies that PSE has actually capitalized its operations over the past several years with lower equity ratios than allowed by the Commission for rate-setting.[345]

274 Mr. Hill says that each percentage point of equity ratio in PSE's capital structure used for rate setting costs customers $4.7 million annually, when income taxes are considered. He also states that the holding company structure in which PSE now resides contains substantially more debt than does PSE and that increases in PSE's equity share and return on equity serve only to service that debt.[346] He claims that third-party debt held by entities in the holding Company structure has increased beyond what was contemplated in the merger proceeding.[347] Considering these factors, he argues it is inappropriate to set rates on a capital structure similar to the regulated utility's capital structure.[348] Indeed, Mr. Hill says that the 46 percent equity ratio agreed to in the settlement of PSE's last rate case was too "equity rich" and that the 43 percent he recommended in that case would be appropriate to use here.[349]

275 Public Counsel argues that it would inappropriate to provide more cash flow to PSE's corporate owners by now increasing the share of equity its regulatory capital structure

---

[343] *Id.* at 26:10-27:7.

[344] Exhibit SGH-1HCT (Hill) at 8:16-21. We note that this appears to be an error. PSE's corporate credit rating was BBB- during this period. This is still investment grade, but not as high a quality as Mr. Hill indicates.

[345] *Id.* at 8:22-9.

[346] *Id.* at 9:13 – 17:12.

[347] Exhibit SGH-1HCT (Hill) at 13:2-18.

[348] *Id.* at 17:16 – 18:4

[349] *Id.* at 18:7-22.

because the average equity ratio in the electric industry is 44 percent, because triple-B rated electric utilities have an average equity ratio of 40 percent, because PSE has not proven any increase in operational risk since the last rate case, and because PSE says it has no concerns about funding its capital budget plans. Public Counsel argues that reducing the Company's equity ratio from 46 to 43 percent is appropriate because this level is actually higher than the average level over the last four years during which Public Counsel contends PSE maintained its financial position.[350]

276 Mr. Gaines contends on rebuttal that the equity ratios in the capital structures advocated by Staff and Public Counsel should be rejected because they are:

- Lower than the equity ratio approved in the Company's last general rate case.
- Lower than the common equity ratio currently employed by PSE.
- Lower than the common equity ratio to be employed, on average, during the rate year.
- Lower than the average common equity ratio recently approved by state regulatory commissions.

He argues that the Commission should reject Staff's use of comparative statistics for equity ratios of other utilities because the ratios Staff used are based on "per-books" figures that include unregulated operations.[351] Mr. Gaines urges the Commission to reject Public Counsel's recommended 43 percent equity ratio because he says it is not supported by any rationale other than that it is the recommendation Public Counsel made in the last rate case.[352] Mr. Gaines objects to the suggestion that the Company's equity ratio should be based on the ratio used over the last few years because, he says, this ignores the Company's and Commission's efforts to strengthen the Company's balance sheet and ignores the equity investments made by Puget Holdings. Taking aim at Staff and Public Counsel, Mr. Gaines contends that both parties' recommendations ignore the financial plans explained and approved as part of the

---

[350] Public Counsel Initial Brief at ¶¶ 8-14.

[351] Exhibit DEG-11HCT (Gaines) at 4:8-6:11.

[352] *Id.* at 7:19-23.

merger transaction.[353] He denies Public Counsel's contention that any entity in the holding company structure issued new third-party debt.[354]

277 Finally, Mr. Gaines contends that the capital structure, cost of equity, and other revenue adjustments proposed by Staff and Public Counsel would cause PSE's credit metrics to fall below Standard & Poor's expectations and would not allow PSE to maintain its current credit rating.[355]

278 *Commission Determination:* The Commission observed in its order setting rates in the Company's most recent fully litigated case that it "has approved hypothetical capital structures when there was a clear and compelling reason to do so."[356] In this case there appear to be two related reasons:

1) The Company argues persuasively that the utility's actual capitalization in the test year and early post-test year period was affected by short-term circumstances and is not representative of how it will capitalize its operations in the rate year.

2) There is no dispute among the parties that the actual capital structure during the test year or shortly after is not a true measurement of how the Company will, or should capitalize its operations.

Thus, we are left to answer the question of which, if any, of the proposed hypothetical structures should be accepted as appropriate for setting prospective rates.

279 The Commission approved the Company's current cost of capital in the fall of 2008 based on an all-party settlement, which included a capital structure with 46 percent common equity. Two major developments affecting the Company and potentially affecting its cost of capital have occurred since the August 2008 settlement: the completion of the sale of Puget Energy to Puget Holdings, and the financial crisis that severely affected all capital markets beginning with the collapse of Lehman Brothers in September 2008.

---

[353] *Id.* at 6:16-7:15 and 8:18 -11:14.

[354] *Id.* at 11:3-20.

[355] *Id.* at 26:18-28-12.

[356] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-060266 and UG-060267, Order 08 (January 5, 2007).

280 The Commission approved the Company's execution of the Puget Holdings transaction in December 2008. As Mr. Hill observed at hearing, the terms of the rate case settlement proposed in August 2008 were known and accepted by all parties, including the Company's potential new owners, during the Commission's review and ultimate approval of the sale of Puget Energy to Puget Holdings.[357] In its order approving the transaction, the Commission approved a condition that the equity-share in the utility's capital structure would not be allowed to fall below 44 percent, unless the Commission approved a lower level of equity for ratemaking purposes.[358] In addition, the order prohibited PSE from declaring or making any dividend distributions if its equity capitalization dropped below 44 percent, again subject to exception if the Commission approves a lower level of equity for ratemaking purposes.[359] Finally, the Commission directed that determination of the cost of equity in the Company's allowed rate of return in future rate cases "will include selection and use of one or more proxy group(s) of companies engaged in businesses substantially similar to PSE, without limitation related to PSE's ownership structure."[360]

281 Turning to the financial crisis, our record shows that the capital markets suffered significant distortions beginning in early fall 2008 and extending through much of 2009. Among these distortions was a significant increase in the "yield spread" between debt issued by the U.S. Treasury and corporate bonds, including utility bonds. Our record also shows that the capital markets have substantially recovered from the distortions caused by the financial crisis and now again reflect cost characteristics similar to, if not lower than, those extant before the onset of the crisis.

282 Our determination of an appropriate capital structure must therefore consider the following:

- All parties agreed to a capital structure with 46 percent equity prior to approval of the Puget Holdings transaction and prior to the onset of the financial crisis.

---

[357] Tr. at 723:5-724:14 (Hill).

[358] *Re Puget Holdings and PSE,* Docket U-072375, Order 8, Appendix A to Stipulation, Commitment 35 (December 30, 2008).

[359] *Id.* Commitment 36.

[360] *Id.* Commitment 24, as clarified by the Commission's Eighth Condition.

- Disruptions in the capital markets have stabilized at levels similar to pre-crisis conditions.

283 Considering these factors, we determine that the appropriate equity share in the Company's capital structure should remain at the currently allowed 46 percent.

2. Cost of Long-Term Debt

284 In its original filing, the Company included a 6.82 percent average cost of long-term debt using the yield to maturity, maturity date, net proceeds to PSE, and coupon- rate for each existing debt issue as well as for the incremental contribution to debt cost of issuing three new debt issues to replace six debt issues that will mature before the end of the rate year.[361] In testimony filed September 28, 2009, Mr. Gaines revised the average cost of long-term debt downward to 6.70 percent to reflect the effect of $350 million Senior Secured Note issued at 5.75 percent on September 11, 2009.[362] This is the long-term debt cost PSE's recommends in its brief.

285 Mr. Parcell testifies for Staff that the Company's proposed 6.70 percent cost for long-term debt includes the cost of two future debt issues to be sold in 2010. He argues these future issues should carry an imputed price equal to the 5.75 percent rate the Company secured for its most recent debt issue in September 2009. Staff contends that the 5.75 percent rate is the most appropriate to impute to the Company's expected rate year debt issuances because that rate is what the Company actually experienced in the capital markets.[363]

286 Public Counsel accepts the Company's cost of long-term debt.

287 PSE argues that the Commission should reject Staff's proposed cost of long-term debt because Mr. Parcell "arbitrarily uses the interest rate on PSE's most recent senior secured note issue."[364] PSE states that this rate is the lowest coupon that PSE has ever

---

[361] Exhibit DEG-1T (Gaines) at 24:3 – 26:10.

[362] Exhibit DEG-9T (Gaines) at 12:4-14:11.

[363] Staff Reply Brief at ¶ 15.

[364] PSE Initial Brief at ¶ 65.

received on a 30-year senior secured note issue. PSE argues that Staff did not produce any evidence that PSE could issue bonds at such a low rate in the future.

288 *Commission Determination:* Ideally, the cost rate for debt in PSE's capitalization is directly measurable as the cost of debt outstanding in the Company's actual capital structure. In this case, however, the Commission is faced with approving a hypothetical, rather than an actual capital structure and it is, to a degree, forward-looking. The Company estimates what its aggregate average cost of long-term debt will be taking into account the replacement of debt issues that will mature before the end of the rate year. While Staff asserts that the estimate of cost for new debt issues should be based on the Company's most recently negotiated bond issue, it is undisputed that the rate the Company achieved is unprecedented. It is significant in this connection that at the time of the recent issue, the Company's actual capital structure included more than 50 percent equity. Thus, the attractive rate on the recently issued debt reflects a capital structure with substantially less leverage than the 46 percent equity share that was approved in PSE's last general rate proceeding and that will remain unchanged as a result of our decisions here.

289 We accordingly find appropriate the Company's proposed average cost rate for long-term debt: 6.70 percent.

3. Cost of Equity

290 The Commission last determined a return on equity capital for PSE based on a fully litigated record in January 2007. In that general rate proceeding, the Commission found an ROE of 10.4 percent, the mid-point of a range from 10.3 to 10.5 percent, to be appropriate for setting rates. The record in that proceeding contained a large volume of expert testimony and a remarkable range in analytic estimates. The Commission observed that little of the evidence focused on circumstances that would justify a change in the Company's cost for equity capital from that previously authorized. Instead, the evidence in that proceeding focused on familiar and rather academic disputes regarding methods, theories and assumptions based on the professional judgment and orientation of the experts.

291 During the intervening three years, the Company and parties again presented substantial evidence on cost of equity in PSE's general rate case filed in late 2007. That case was ultimately resolved by settlement in August 2008 when the parties agreed to, and the Commission approved, a return on equity of 10.15 percent.

292 In this case, we are once again presented with a substantial body of evidence, this time marshaled in support of ROE recommendations that range from 9.5 percent to 10.8 percent. This range continues to be accounted for by disagreements regarding the growth rates to apply in the DCF method and the market risk premiums to apply in the CAPM and Risk Premium methods. It is not unusual for experts to disagree over these key analytic elements and assumptions. The Commission has said in more than one order that it appreciates and values a variety of perspectives and analytic results because these serve to better inform the judgment it must exercise than would a single model, or a single expert's opinion. We reiterate that perspective here. We value and rely on multiple methodologies, models and expert opinions to develop a robust record of evidence to inform our judgment. It is particularly important to take multiple methods and models into account in the present circumstances of financial turmoil that may affect the input values and assumptions used in each method.

293 As is usually the case, much of the dispute among the experts testifying in this case involves "analytic judgment" concerning key data assumptions and model application. These disputes are not resolvable on the basis of objective tests – their resolution requires the application of considerable judgment when we review the expert testimony. In our experience there is no precise or single right answer to these analytic questions.

294 Table 10 presents the range in analytic results calculated by the cost of capital experts, and each party's final ROE recommendation.

TABLE 10
ROE Analytical Estimates

	Dr. Morin[365]	**Mr. Parcell**[366]	**Mr. Hill**[367]
DCF	10.3 – 11.3	9.6 – 11.3	9.57 - 9.87
Risk Prem.	10.34	N/A	N/A
CAPM	9.3-9.7	7.9 – 8.2	7.79 – 8.49
MEPR	N/A	N/A	9.19 – 9.33
MTB	N/A	N/A	9.6 – 9.71

[365] Dr. Morin's results are presented as he revised them to remove the effect of flotation. Exhibit B-7.

[366] Exhibit DCP-1T (Parcell) at 44:13-15

[367] Exhibit SGH-1HCT (Hill) at 40:18-19 and 55:15-56:13

Comparable Earnings	N/A	9.5 – 10.5	N/A
Party Recommendation	**10.8**	**10.0**	**9.5**

295 Our record in this proceeding differs in at least two important ways from the evidence we have considered in past proceedings. Here the experts acknowledge openly that the analytic models are difficult to use and interpret in the context of volatile financial markets. And here, the circumstances of the utility have changed with completion of the Puget Holdings transaction.

296 Neither of these factors, however, turns out to be centrally important for setting the ROE in this case. The Commission's order approving the Puget Holdings transaction makes clear that the nature of the utility's ownership is not a limiting factor for determining a fair equity return based on businesses substantially similar to PSE without regard to ownership structure. Our record also shows that while the analytic ROE models may presently be affected by recent market turmoil, it appears that market conditions themselves have recently returned to more normal circumstances.

297 With this background in mind, we turn to the analytic estimates and opinions of the three experts. Despite the rich diversity in their opinions and results, their analyses provide a solid foundation on which we can construct a reasonable range for ROE.

298 All of the experts provide DCF results, supported to one degree or another by each expert's alternative methodologies, which differ from one expert to the next. DCF results, like other analytic models, are subject to bias in perturbed markets because the critical yield component is affected by utility stock prices, which have been somewhat volatile recently.[368] This may lead to a significant divergence of opinion among the experts despite their use of a common approach. Nonetheless, we find the experts' DCF results overlapping in this case – Mr. Parcell's results overlap with Mr. Hill's at the low end and with Dr. Morin's at the high end.

299 In this context, we also find that Mr. Hill's DCF estimates for Public Counsel are persuasively critiqued by Dr. Morin for the Company because they rely on growth estimates that are obscure and not subject to replication. We find, too, that Dr. Morin's DCF results are persuasively critiqued by Mr. Hill because they rely solely

[368] This is because, for a given dividend, elevated stock prices depress the yield and lower stock prices increase the yield. In like fashion, for a given stock price, increased dividends increase yield and lower dividends decrease yield.

on analysts' forecasts of earnings growth, without benefit of historical rates of growth and other information published by the analysts or other reputable financial sources.

300 In contrast, Mr. Parcell's DCF estimates are derived from a broad set of published growth figures that are transparent and include both forward-looking estimates and historical data. His DCF results span the ground between the 9.87 percent high end of Mr. Hill's DCF range and the 10.3 percent low end of Dr. Morin's DCF range. The mid-point of this range is 10.1 percent. Mr. Parcell's comparable earnings results of 9.5 percent to 10.5 percent also encompass this middle-ground and have a mid-point of 10.0 percent. Considering that the experts' other corroborating analyses, including CAPM results, produce results below 10 percent, we discount the high end of Mr. Parcell's and Dr. Morin's DCF results.[369] Taking all of this into account, we are confident that a reasonable ROE for PSE can be found within the range of 9.9 percent to 10.3 percent. This zone of reasonableness is made somewhat wider than the zones we have determined in past cases because of the circumstances affecting the financial markets and the effect of these circumstances on application of the analytic ROE models.

301 *Commission Determination:* Considering all of the above, we determine that PSE's cost of equity capital should be set at 10.1 percent for purposes of setting rates in this proceeding. Coupled with our decision to set PSE's equity share at 46 percent, the Company's computed weighted average cost of equity is 4.65 percent.

4. Capital Structure and Cost of Capital Summary

302 We summarize our determinations of the issues concerning Capital Structure and Cost of Capital above in Table 9. As shown there, our findings and conclusions concerning the appropriate capital structure and component cost rates produce an overall weighted cost of capital of 8.10 percent.

303 We are mindful of our responsibility to set the allowed return on capital at a level "sufficient to assure confidence in the financial integrity of the enterprise, so as to

---

[369] The CAPM results in this case fall below, in some cases substantially below, estimates derived from the other analytic approaches. All of the experts note that the CAPM may be less reliable in current circumstances, though Mr. Parcell recommends that CAPM results should be used to corroborate DCF analyses. We agree, but in these unusual financial circumstances we have accorded the CAPM results diminished weight.

maintain its credit and to attract capital."[370] The credit metrics by which the debt rating agencies develop and evaluate utility credit ratings are one measure of this confidence. Standard & Poor's (S&P) publishes a matrix of credit metrics it looks to when rating the quality of utility credit.[371] Mr. Gaines, in his testimony, estimates the credit metric ratios for each of the parties' revenue requirements cases.[372] We have carefully examined this evidence and are satisfied to find that the ratios Mr. Gaines calculates for Staff's case fall within the S&P ranges for a company rated BBB with the excellent business and aggressive financial risk profiles S&P assigns to PSE. Considering that the results of our Order here allow for a higher rate of return and recovery of more revenue than what Staff recommends, we are confident that our decision will allow the Company, with prudent management, to maintain or improve its current credit rating.

D. Electric Rate Spread and Rate Design Settlement

304 Rate spread allocates the revenue requirement to each of PSE's customer classes. Rate design is the pricing mechanism for PSE to recover its costs. Rate design determines the rates that each individual customer actually pays.

305 PSE, Staff, and other parties that took an active interest in the electric rate spread and rate design issues submitted a proposed Multiparty Settlement Agreement on July 25, 2009, which they ask the Commission to approve and adopt to resolve all rate spread and rate design issues. The Settlement Agreement is supported by Joint Testimony addressing why the Agreement will result in rates that are just and reasonable, and consistent with established Commission policies. It is unopposed.

306 The parties agree to use PSE's electric cost-of-service study, rate spread, and rate design. According to the Settlement Agreement, any revenue requirement increase ordered in this proceeding will be allocated among the various customer classes and rate schedules in proportion to the rate spread proposed by PSE. The Settlement

---

[370] *FPC v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

[371] *Criteria Methodology: Business Risk/Financial Risk Matrix Expanded.* Standard & Poor's. Global Credit Portal. RatingsDirect. May 27, 2009. We take administrative notice of this industry publication.

[372] Exhibit DEG-19 (Gaines) at 2.

Agreement includes an illustrative example or "baseline" that uses a hypothetical final electric revenue requirement increase of $113 million.

307 The Settling Parties state in their Joint Testimony that the rate spread set forth in the Multiparty Settlement, and illustrated on page 1 of its Attachment, represents a reasonable balancing of the factors traditionally used by the Commission to set rates, including cost-of-service, fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.[373] According to the parties' Joint Testimony, most electric rate classes already are relatively close to parity (*i.e.*, rates recover 97% to 130% of the costs caused by a given customer class). The proposed rate spread is designed to bring each rate class even closer to parity without causing rate shock.

308 The Multiparty Settlement assigns a uniform percentage rate increase to Residential Schedules 5and 7, and Schedules 24, 26, 31, 35, 43, 46, 49, 50-59, 448, and 449.[374] At the illustrative baseline increase, this is a 5.83% percent increase. Mid-sized commercial and industrial customers (*i.e.,* secondary voltage customers with demand between 50 and 350 kW) under Schedules 25 and 29 are assigned 75 percent of the uniform percentage rate increase assigned to the other rate schedules, or 4.37% percent, assuming the illustrative baseline increase. Schedule 40 (*i.e.*, campus rate) rates for power supply (generation and transmission) are set equal to the Schedule 49 (*i.e.,* high voltage) charges (adjusted for power factor and losses). In addition, delivery-related charges are derived based upon customer specific costs of PSE's distribution facilities used to directly provide delivery services to the Schedule 40 customers.

309 In terms of rate design, the proposed settlement produces no major change from current practice. The rate design follows the methods proposed by PSE,[375] except for the one phase basic charge for residential service under Schedule 7 and rates under

---

[373] Exhibit JST-2 (Higgins, Phelps, Schoenbeck, Schooley and Watkins) at 6:9-15.

[374] Schedules 24 and 26 are smaller (*i.e.*, demand less than 50 kW) and larger (*i.e.*, demand greater than 350 kW) secondary voltage commercial and industrial customers. Schedules 31, 35 and 43 are primary voltage customers. Schedules 46 and 49 are high voltage customers. Schedules 50 and 59 are lighting customers. Schedules 448 and 449 are "choice" and retail wheeling customers.

[375] *See generally* Prefiled Direct Testimony of Mr. David W. Hoff, Exhibit DWH-1T, the Rebuttal Testimony of Ms. Janet K. Phelps, Exhibit JKP-25T and supporting exhibits. Multiparty Settlement Agreement Re: Electric Rate Spread and Rate Design, Attachment, page 2.

Schedule 26. The parties agreed that the one phase basic charge for residential service under Schedule 7 will increase from $7.00 to $7.25. As to Schedule 26, PSE accepted Kroger's proposal to link both the demand and energy charges of Schedules 26 and 31 so that the differential between the demand and energy charges of the two schedules is equalized.[376]

310 There is substantial evidence in the record supporting the electric rate spread and rate design proposals embodied by the Multiparty Settlement Agreement.[377] We determine the electric rate spread and rate design proposals presented in the parties' Settlement Agreement are reasonable and should be approved and adopted. The Settlement Agreement is attached and incorporated into this order as Appendix A.

E. Natural Gas Rate Spread and Rate Design Settlement.

311 PSE, Staff, and other parties interested in natural gas rate spread and rate design also submitted their proposed Multiparty Settlement Agreement on July 25, 2009. As in the case of the electric settlement discussed above, they ask the Commission to approve and adopt their agreement to resolve all rate spread and rate design issues. The Settlement Agreement is supported by Joint Testimony addressing why the Agreement will result in rates that are just and reasonable, and consistent with established Commission policies. No party opposed this Multiparty Settlement.

312 The Multiparty Settlement assigns a share of the PSE revenue requirement to each rate schedule based on a rate spread that is derived using a hypothetical increase of $28 million as a baseline. These respective shares of the revenue requirement are then used to apportion any rate increase of a differing amount.

313 At the baseline revenue requirement, the Multiparty Settlement assigns a uniform percentage rate increase of 7.4 percent to residential Schedules 16, 23, 53 (propane); smaller volume commercial Schedules 31and 61; and water heater rental Schedules 71, 72, and 74. Schedules 41 and 41T, large volume commercial and industrial Schedules, are assigned increases equal to 75 percent of the uniform percentage rate

---

[376] Exhibit JKP-25T (Phelps) at 28:2-10.

[377] Prefiled Direct (Exhibit JKP-1T) and Rebuttal Testimony of Janet K. Phelps (Exhibit JKP-25T), and supporting exhibits; Prefiled Direct Testimony of David W. Hoff (Exhibit DWH-1T), and supporting exhibits; Exhibit JST-2 (Joint Settlement Testimony of Higgins, Phelps, Schoenbeck, Schooley and Watkins: Electric Rate Spread and Rate Design).

increase assigned to the residential, smaller commercial and water heater customers, or 5.5 percent. Finally, the interruptible customers on Schedules 85, 85T, 86, 86T, 87, and 87T are assigned a rate increase equal to 50 percent of the uniform percentage rate increase assigned to residential, smaller commercial and water heater customers, or 3.7 percent.

314 The rate design structure proposed under the Settlement Agreement is similar to the current structure. The rate design follows the methods proposed by PSE,[378] except for residential service under Schedules 23 and 53. Under the agreement, the basic charge for residential service under Schedules 23 and 53 will remain at $10.00 per month, rather than being increased to $10.73, as PSE originally proposed.

315 There is substantial evidence in the record supporting the natural gas rate spread and rate design proposals embodied by the Multiparty Settlement Agreement.[379] We determine the natural gas rate spread and rate design proposals presented in the parties' Settlement Agreement are reasonable and should be approved and adopted. The Settlement Agreement is attached and incorporated into this order as Appendix B.

F. Prudence Issues

1. Mint Farm

316 PSE purchased the Mint Farm Energy Center (Mint Farm), a 311 MW natural gas-fired, combined cycle combustion turbine (CCCT) generation facility located in Longview, Washington on December 5, 2008. Mint Farm is currently part of the PSE's resource portfolio serving customers.[380]

317 PSE requests a Commission determination that it was prudent to acquire Mint Farm. PSE also asks the Commission to determine that Mint Farm complies with the greenhouse gases emissions performance standard (EPS) established by RCW 80.80.

---

[378] *See generally*, Exhibit JKP-1T (Phelps) and supporting exhibits. Multiparty Settlement Agreement Re: Natural Gas Rate Spread and Rate Design, Attachment, page 2.

[379] *See generally*, Exhibits JKP-1T and JKP-25T (Phelps), and supporting exhibits; *see also* Exhibit JST-4 (Joint Settlement Testimony of Higgins, Phelps, Schoenbeck, Schooley and Watkins: Natural Gas Rate Spread and Rate Design).

[380] Exhibit DN-1T (Nightingale) at 9:18-19.

Although this question also informs our prudence determination,[381] we discuss it separately below.

318 Staff, through its testimony and in its brief, supports the Company on both questions. Public Counsel, however, disputes the prudence of the Mint Farm acquisition. While not directly addressing the EPS issue, Public Counsel challenges the Company's request that the facility be classified as "baseload" for purposes of RCW 80.80. Were the Commission to determine it is not a baseload facility, the statute simply would not apply, mooting the question whether it meets the EPS.

319 The leading decisions in which the Commission articulates its standard for determining prudence are the Eleventh and Nineteenth Supplemental Orders in PSE's 1992 general rate case and other consolidated dockets.[382] The Commission held, pursuant to RCW 80.04.130, that the utility has the burden of proof on prudence, and "must make an affirmative showing of the reasonableness and prudence of the expenses under review."[383] The Commission reaffirmed the standard it applies in reviewing the prudence of power generation asset acquisitions in 2003:

> The test the Commission applies to measure prudence is what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. The company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made.[384]

320 The Commission continues to evaluate prudence considering specific factors identified in its earlier decisions. In particular, the Commission requires the Company to show:

---

[381] *WUTC v. PacifiCorp, d/b/a, Pacific Power & Light Co*., Docket UE-090205, Order 09 at ¶67 (December 16, 2009).

[382] *WUTC v. Puget Sound Power & Light*, Docket Nos. UE-920433, UE-920499, UE-921262 (consolidated)(*PSE 1992 GRC)*; Eleventh Supplemental Order, Nineteenth Supplemental Order.

[383] *Id.* Eleventh Supplemental Order at 19.

[384] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at ¶ 19 (April 7, 2004).

- The new resource is needed.
- The new resource fills the need determined in a cost-effective manner, evaluating that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.
- Management kept its board of directors informed and involved the board in the decision process.
- The Company has adequate contemporaneous records that will allow the Commission to evaluate its actions with respect to the decision process. [385]

Public Counsel's challenge to the prudence of PSE's Mint Farm acquisition concentrates on the first two factors.

321 On the question of need, PSE documented through its testimony and exhibits its current and projected need for new 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 baseload demand of PSE's customers.[386] The Company's 2007 IRP indicated that the lowest reasonable cost electric resource strategy to pursue at the time would rely on gas-fired CCCT generating capacity to the extent its energy needs cannot be met through demand-side and renewable resources.[387]

322 PSE updated its 2007 IRP load forecast before issuing a request for proposals (RFP) in 2008. PSE's energy need for supply-side resources for the 2008 RFP was 143 aMW by 2011.[388] The supply-side energy need grew to 700 aMW by 2012 and 977

---

[385] *PSE 1992 GRC,* Nineteenth Supplemental Order at 5-11.

[386] Exhibit KJH-8T (Harris) at 4:5-9. 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* Exhibit WJE-21HCT (Elsea) at 5:9 – 7:4

[387] Exhibit KJH-5 at 218-219 (2007 IRP, pages 8-2 and 8-3).

[388] Exhibit WJE-3.

aMW by 2013.[389] There were also significant capacity needs of 208 MW by 2011, 760 MW by 2012, and 771 MW by 2013.[390]

323 Contesting PSE's asserted need for resources – specifically Mint Farm – Public Counsel cites to a presentation to PSE's Board of Directors dated August 4, 2008, which indicated that Mint Farm would create surplus capacity on PSE's system through 2011.[391] PSE and Staff argue that Public Counsel's position in this regard ignores the reality of resource acquisition. Specifically, Staff points out that CCCTs become available in large blocks of capacity in a timeframe not often matched perfectly to demand.[392] As a result, Staff says, acquiring such "lumpy" resources means the Company's power portfolio may at times be long.[393] Staff argues that "PSE's 2007 IRP showed a need for a CCCT by 2011."[394] It follows, Staff reasons, that the fact "Mint Farm created surplus capacity through 2011 is no reason to find the purchase imprudent."[395]

324 The main thrust of Public Counsel's opposition to the Mint Farm acquisition focuses on the second of the prudence evaluation criteria bulleted above: Whether the new resource fills the need determined in a cost-effective manner, evaluating that resource against the standard of what other purchases are available, and against the standard of what it would cost to build the resource itself.

325 As to the question of the cost of Mint Farm relative to what it would cost PSE to build such a resource, Staff states that "PSE purchased the plant at a 30 percent discount

---

[389] *Id*.

[390] *Id*.

[391] Public Counsel Initial Brief at ¶ 33; Exhibit SN-1HCT (Norwood) at 9:4-6.

[392] Exhibit DN-1HCT (Nightingale) at 15:19-20.

[393] Staff Initial Brief at ¶ 178; *see also* Public Counsel Initial Brief at ¶ 16.

[394] Staff Initial Brief at ¶ 178 (citing Exhibit KJH-5 at 79).

[395] *Id.* Staff states that it finds Public Counsel's position on Mint Farm in this connection "striking given his position in PacifiCorp's 2009 GRC." Staff Initial Brief at ¶ 177. In that case, Public Counsel agreed that the Chehalis Generating Plant was a prudent acquisition by PacifiCorp, even though the facility was acquired to fill a resource deficit that would not occur until 2012 according to an IRP. The Commission agreed the acquisition was prudent, commenting on the benefit of acquiring a plant that, like Mint Farm, otherwise was a "lost opportunity." *WUTC v. PacifiCorp, d/b/a, Pacific Power & Light Co*., Docket UE-090205, Order 09 at ¶¶ 50, 66 (December 16, 2009).

from the cost to build a new facility."[396] This does not appear to be in dispute. Certainly, then, Mint Farm is cost-effective when measured against what it would cost to build a comparable resource, and taking into account the construction risk of a self-build option.

326 PSE used a two-phase process to analyze the qualitative and quantitative advantages and disadvantages of each of the 31 proposals it received in response to the 2008 RFP. [397] The qualitative evaluation addressed compatibility with PSE's resource needs, cost minimization, risk management, public benefits, and other strategic, technical and financial factors.[398] The quantitative evaluation examined each proposal using three measures: the Portfolio Benefit, the Portfolio Benefit Ratio, and the 20-Year Levelized Cost.[399]

327 Staff provides a useful summary of the evidence showing why Mint Farm emerged from the evaluation process as a candidate for acquisition, as follows:[400]

- Mint Farm provided a significant contribution to meeting PSE's energy and capacity needs over the mid- to long-term.[401]

- Mint Farm minimized PSE's cost of power relative to new CCCT construction.[402]

- Mint Farm had a low heat rate compared to other CCCTs.[403]

---

[396] Staff Initial Brief ¶ 162 (citing Exhibit RG-53HCT (Garratt) at 27:21-22 and 44:15-16).

[397] Exhibit WJE-1HCT (Elsea) at 9:5-10.

[398] Exhibit RG-1HCT (Garratt) at 6:20-7:5 and Exhibit RG-3HC (Garratt) at 13.

[399] Exhibit RG-3HC (Garratt) at 15.

[400] Staff Initial Brief ¶ 169.

[401] *Id.* (citing Exhibit RG-1HCT (Garratt) at 42:7-14).

[402] *Id.* (noting that Mint Farm's "all-in" cost is about 60 percent of the price for new CCCT construction. Citing Exhibit RG-1HCT (Garratt) at 42:15-19 and comparing to Exhibit RG-3HC (Garratt) at 179 and Exhibit WJE-1HCT (Elsea) at 30:10).

[403] *Id.* (citing Exhibit DN-1T (Nightingale) at 5:13-19 and noting that a lower heat rate means that Mint Farm requires less fuel supply than a higher heat rate CCCT to produce the same amount of energy).

- Mint Farm had pre-existing electric transmission rights in Western Washington.[404]

- Mint Farm had sufficient gas transmission and supply.[405]

- Mint Farm was a new plant that, with good maintenance, had an expected service life of 25-30 years.[406]

- Mint Farm posed no risk of construction or counterparty default since it was an existing, operational facility.

- As the last available CCCT in Washington with firm transmission rights, Mint Farm was a unique opportunity not likely to remain available during the Company's next RFP.[407]

- Mint Farm provided flexibility to meet variable loads including integrating wind resources.[408]

In addition, Mint Farm had a positive Portfolio Benefit and Benefit Ratio, although not as high as an alternative PPA (purchase power agreement) that also was under consideration.[409]

328 Public Counsel argues that because the alternative PPA scored higher than Mint Farm in terms of the Portfolio Benefits and Benefit Ratio metrics, Mint Farm should have

---

[404] *Id.* Exhibit RG-1HCT (Garratt) at 30:10-17. PSE acquired Mint Farm with a minor deficiency of firm transmission capacity: 3 MW of Mint Farm's baseload capacity of 296 MW. However, PSE identified methods to manage this small deficit. Exhibit RG-53HCT (Garratt) at 42:11-43:12.

[405] *Id.* (citing Exhibit RCR-1CT (Riding) at 2-7 and noting that PSE had a strategy to ensure firm capacity sufficient to deliver the full requirements to Mint Farm. Exhibit RCR-6T (Riding) at 2-7.) Staff notes further that the strategy appears to have worked in that sufficient gas has been delivered whenever plant operations were warranted, including during December 2009 when record demands were recorded due to cold weather. Exhibit RCR-6T (Riding) at 7:3-6).

[406] *Id.* (citing Exhibit DN-1T (Nightingale) at 16:14-19).

[407] *Id.* (citing Exhibit DN-1T (Nightingale) at 17:1-5 and noting that the Grays Harbor CCCT is the only other CCCT not under long-term contract, but it does not have available firm transmission capacity until 2015. Exhibit RG-1HCT (Garratt) at 43:1-8 and Exhibit RG-53HCT (Garratt) at 7:17-20).

[408] *Id.* (citing Exhibit DN-1T (Nightingale) at 15:10).

[409] Exhibit RG-3HC (Garratt) at 119 and Exhibit WJE-11HC (Elsea) at 28.

been rejected in favor of the PPA. Staff and PSE argue, however, that this ignores that Mint Farm's 20-Year Levelized Cost was 30 percent less than the alternative PPA, even with the financial burden of Mint Farm acquisition costs and surplus capacity through 2011.[410] Thus, according to Staff, "the added costs of Mint Farm before 2012 were outweighed by the increased benefits of its lower longer-term operating costs."[411] More significant, perhaps, is PSE's argument that: "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."[412]

329 Public Counsel also argues PSE's decision to acquire Mint Farm was imprudent because the Company did not have adequate firm gas transportation capacity to supply the full requirements of the facility, or sufficient firm transmission rights to deliver the full output of Mint Farm to its system.[413] Public Counsel states that PSE also knew that Mint Farm had no back-up fuel capability, which he argues increased the risk that the output of the plant could be restricted if the natural gas supply were to be curtailed for any reason.[414]

330 Characterizing Public Counsel's contentions concerning firm gas transportation capacity and firm transmission rights, PSE states that Public Counsel:

> 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 unused

---

[410] *Id.*

[411] Staff Initial Brief at ¶ 182. Staff notes that Public Counsel misses the point in his attempt to show that the 20-Year Levelized Cost need not be evaluated independently because it uses the same cost inputs as the Portfolio Benefit and Benefit Ratio. Tr. 223:13-224:4 (Garratt) and Tr. 290:12-292:21 (Elsea). Staff states that the 20-Year Levelized Cost is the only criteria that measures the expected costs to deliver power for a specific resource over 20 years. Tr. 290:12-22 (Elsea). Thus, Staff argues, even if it shares cost inputs with the Portfolio Benefit and Benefit Ratio, it provides unique analytical results that were evaluated separately and collectively with all other quantitative and qualitative factors. Tr. 225:10-24 (Garratt) and Tr. 289:6-25 (Elsea).

[412] PSE Initial Brief at ¶ 17 (citing Exhibit RG-53HCT (Garratt) at 17:7 – 22:17).

[413] Exhibit RG-1HCT (Garratt) at 30-31.

[414] Exhibit RG-1HCT (Garratt) at 31-32; Exhibit SN-1HCT (Norwood) at 16.

> firm capacity on such system, to adequately serve the gas requirements of the Mint Farm Energy Center.[415]

And, as to transmission rights, PSE says:

> 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.[416]

331 On the question of back-up fuel capability, Mr. Garratt testified:

> Public Counsel, however, fails to acknowledge that it would be nearly impossible to permit a baseload combined cycle combustion turbine in Washington for both natural gas and oil due to the high-polluting emissions of oil. Furthermore, Public Counsel is, in effect, questioning the firmness of firm gas transportation. Although it is possible that the fuel supply could be curtailed, it is not likely.[417]

Mr. Garratt's points are well taken. Concerning the prospect of obtaining a permit for a plant with oil as a backup fuel, the Washington Energy Facility Site Evaluation Council expressed its view as early as 2002 that developers should not include such a proposal in their plans if they wished to obtain a positive recommendation from the Council.[418] As to Mr. Garratt's second point, there is no evidence of any curtailment of firm gas transportation by Northwest Pipeline or Cascade in recent years or, indeed, at any time.

332 Staff observes that Mint Farm will run many more years and many more hours in any year due to its longer service life and lower heat rate relative to alternatives. On this

---

[415] PSE Initial Brief ¶ 20 (citing Exhibit RCR-6T (Riding) at 2:2 –7:6).

[416] *Id.* ¶ 21 (citing Exhibit RG-53HCT (Garratt) at 43:3-6).

[417] Exhibit RG-53HCT (Garratt) at 43:16-21.

[418] *In the Matter of: Application No. 99-01, Second Revised Application, Sumas Energy 2, Inc., Sumas Energy 2 Generation Facility,* Council Order No. 768, Findings of Fact, Conclusions of Law, and Order Recommending Approval of Site Certification on Condition (May 24, 2002) (discussion of Air Quality at 29 – 34).

basis, Staff argues that if PSE had acquired the alternative PPA that Public Counsel says was a superior resource, PSE would have been exposed more often to variable market pricing because the PPA would have produced less energy to meet load.[419] Even Public Counsel's witness on the Mint Farm issue acknowledges that that "in the long-run ownership of Mint Farm should benefit customers."[420]

333 Mr. Garratt testified that the alternative PPA was not a suitable fit to meet PSE's resource needs in 2011 due to pre-existing contractual requirements.[421] It was placed on the "Continuing Investigation List" for future monitoring.[422] Staff and PSE both point out opportunities to extend the alternative PPA have not been foreclosed. In the context in which PSE considered Mint Farm, the alternative PPA and other options, Mint Farm was the preferred choice but not the only choice that the Commission might find prudent. Each resource acquisition decision is complex and depends on a host of factors, both quantitative and qualitative. Thus, it would not be appropriate to determine on the basis of one alternative being less attractive than another on one or two measures taken in the overall evaluation process that the Company was imprudent in selecting that alternative.

334 An additional matter Public Counsel raises with respect to PSE's acquisition of Mint Farm is the suggestion that the Company may have been motivated, or improperly influenced to purchase Mint Farm because it adds $230 million to rate base, which increases PSE's revenue requirement due to the return allowed on rate base.[423] PSE presented testimony from several witnesses disputing that this was a factor in its decision making process.[424] Public Counsel argues this evidence is belied to some degree by Mr. Garratt's testimony that acknowledged PSE's August 2008 presentation to the Board included an analysis of the financial impact of the acquisition – a "Financial Pro Forma."[425] Public Counsel also cites to Ms. Harris's testimony on

[419] Tr. 216 (Garratt); Exhibit DN-3HCT (Nightingale) at 5:16-6:16.

[420] Exhibit SN-1HCT (Norwood) at 21:15-16 and Tr. 209:24-210:7 (Harris).

[421] Exhibit RG-53-HCT (Garratt) at 7:12-16.

[422] Exhibit RG-3HC (Garratt) at 26 and Exhibit RG-53HCT (Garratt) at 23:6-15; Tr. 211:8-9 (Harris) and Tr. 281:7-14 (Garratt).

[423] Public Counsel Initial Brief at ¶¶ 51, 52.

[424] Exhibit KJH-8CT (Harris) at 11; Exhibit RG-53HCT (Garratt) at 28-29; Exhibit WJE-21HCT (Elsea) at 15.

[425] Public Counsel Initial Brief ¶ 52 (citing Tr. 230:19-22 (referring to Exhibit RG-7C, August 2008 Board Presentation, Financial ProForma, p. 74, *et seq*.)

cross-examination in connection with this argument. In point of fact, however, Ms. Harris's testimony is that:

> I believe as is stated in the testimony of Mr. Garratt, we're always looking at any sort of financial impact on the company, because that would impact our customers in the long term.[426]
>
> * * *
>
> Your previous questions were do we look at a financial impact for the shareholder. My answer would be no, not specifically for a shareholder. Your other question was do we look at the impact, and yes, we have to look at the credit ratings and even all the aspects revolving around the financial stability of the company. So if the question is do we look at financial impact, yes, but not for shareholder or customer, we're looking at it holistically.[427]

PSE's consideration of the financial impact of an acquisition does not suggest any impropriety in the decision making process.[428]

335 Although Staff supports a Commission determination that PSE's acquisition of Mint Farm was prudent, Staff raises a concern about the plants security and requests that we address it in our order. Staff recommends that the Commission order PSE to perform a detailed potential hazard assessment of the dike system protecting Mint Farm and develop a flood contingency plan to protect the site from flooding.[429] Staff says it is ready to work with PSE on the detail of these measures to ensure they are developed in a timely way without undue burden.

336 PSE objects to this proposal, citing a 2007 inspection report of the U.S. Army Corps of Engineers.[430] However, Staff states, this 4-page document merely concludes,

---

[426] Tr. 198:3-6 (Harris).

[427] Tr. 199:1-9 (Harris).

[428] We note that it would be highly inappropriate for the Company to not consider this important factor. Indeed we expect it and will expect to see evidence in future cases showing that PSE is being diligent in its ongoing resource acquisition efforts to strike an appropriate balance in terms of relying on a financially sound mix of Company-owned generation and purchased power.

[429] Exhibit DN-1HCT (Nightingale) at 20:21-21:3.

[430] Exhibit RG-53HCT (Garratt) at 22:8-17.

without analysis, that "[t]he levee and pumping plants appear to be in good condition."[431] According to Staff, no evidence was presented that the levee has been evaluated for long-term stability and there is no evidence of actual system performance during floods. Staff argues that flood protection facilities should be assessed routinely for structural integrity. Staff says this is especially important for a plant that will run another 25-30 years and is located near the Columbia River on flat land.

337 *Commission Determination:* We determine that PSE was prudent in deciding to purchase the Mint Farm facility. Such decisions are complex and involve consideration of a host of factors when a number of candidate resources are simultaneously evaluated. While one resource may be superior to others by some measures, an alternative resource may be more favorable considering other, equally important criteria. It is clear from the evidence that PSE undertook a careful, thorough and detailed examination of the leading candidates for acquisition that emerged during the evaluation process pursuant to the RFP. PSE ultimately selected Mint Farm from among several alternatives, any one of which the Commission might find prudent.

338 Although we determine PSE's decision to acquire Mint Farm was prudently made, it is appropriate that we discuss our concerns with regard to two issues raised by Public Counsel. There is no dispute that the acquisition of Mint Farm leaves PSE long in terms of capacity during 2010. This means that customers will bear the total costs of the facility in rates during a period when its benefits are not fully realized. But that short term reality does not detract from the mid- and long-term prudence of the acquisition.[432]

339 As we have noted in earlier decisions,[433] acquisitions such as Mint Farm are rarely, if ever, in precise balance with a company's forecasted near-term load. Instead, opportunities such as Mint Farm are predictably out of balance with a company's short-term resource needs because such purchases are opportune in their inception. The timing of these events is driven by the seller. When the seller decides to market

[431] Staff Initial Brief at ¶ 186.

[432] At worst, we expect it to result in a modest intergenerational misalignment of costs and benefits, and see no need to fine tune rates to correct for this minor effect. However, if circumstances should change, we may revisit this issue.

[433] *WUTC v. PacifiCorp, d/b/a, Pacific Power & Light Co*., Docket UE-090205, Order 09 at ¶¶ 50, 66 (December 16, 2009).

its property, potential buyers must act with alacrity or lose their opportunity to acquire the asset. Here, we are convinced that PSE moved to acquire Mint Farm, not because of an immediate need for the resource, but because it offered significant benefits to its generating portfolio at a reasonable price relative to comparable alternatives and the company's longer-term resource needs. There is no evidence that suggests PSE could have waited to act on Mint Farm and achieve the same result.

340 While there is no evidence in the record to support Public Counsel's concerns that PSE's decision to acquire Mint Farm was driven in part by an interest in acquiring a capital asset on which it will earn a return, rather than making a power purchase that would not impact return, the concern is valid as a general proposition. Even in the absence of any evidence of abuse, regulatory authorities in the utility sector must be alert to the potential that a company might make unnecessary or premature capital additions to inflate returns. Utility companies, for their part, should be aware of the regulators' responsibility in this regard. Thus, we expect PSE to continue to evaluate carefully the financial impacts of alternative resource acquisition decisions, both on the Company from a business perspective and on customers in terms of rates. In addition, PSE should continue to evaluate the security of its power supply in terms of its ability to provide safe and reliable service. There should be an appropriate balance in the Company's power portfolio at all times between owned generation and power purchases. Determining the appropriate balance is a matter of informed judgment. We expect PSE to obtain the information necessary to make good judgments in this connection, and to share that information with the Commission on an ongoing basis in the context of IRPs and their updates and general rate cases, and by other means, as appropriate.

341 Turning to Staff's concerns about flood hazard at the Mint Farm site, we do not find it appropriate to require PSE to perform a detailed potential hazard assessment of the dike system protecting Mint Farm and develop a flood contingency plan. It is apparent from our record that PSE is fully aware of its obligation to be prudent when acquiring resources, and we are confident the Company is equally aware of its obligation to prudently manage them on an ongoing basis. Thus, we leave it to the Company, in the first instance, to take appropriate measures considering any environmental hazards that might affect the Mint Farm facility.

2. Uncontested Asset Acquisitions

342 PSE asks the Commission to determine expressly that the Company acted prudently in acquiring the following resources and in executing the following power purchase agreements:

- Purchase of Fredonia Generating Units 3 and 4.
- Expansion of the Wild Horse Wind Facility to add 44 MW of capacity to the facility.
- Execution of a four-year winter power purchase agreement with Barclays Bank PLC.
- Execution of a four-year and three-month power purchase agreement with Credit Suisse.
- Execution of a five-year power purchase agreement with Puget Sound Hydro LLC.
- Execution of a five-year power purchase agreement with Qualco Energy, LLC.[434]
- Execution of a five-year power purchase agreement with Powerex for Point Roberts.[435]

PSE provided evidence concerning, and no party challenges the prudence of, these resource acquisitions.[436]

343 Finally, PSE requests our express determination that the sale of the White River assets to the Cascade Water Alliance was appropriate. PSE provided detailed testimony regarding the sale, the alternatives considered by PSE, and the appropriateness of the consideration received.[437] No party opposed this requested determination.

---

[434] *See* Exhibit KJH-8CT (Harris) at 1:17 – 2:4.

[435] *See* Exhibit DEM-9CT (Mills) at 9:10-13; *see also* Exhibit DEM-1CT (Mills) at 38:8-9.

[436] *See* Exhibit KJH-1CT (Harris) at 8:18 – 9:8; *See passim* Exhibit RG-1HCT (Garratt).

[437] *See* Exhibit PKW-1T (Wetherbee) at 2-18.

344 *Commission Determinations:* No one opposes a Commission determination that the resource acquisitions discussed in this section of our Order are prudent and PSE has presented satisfactory evidence that this is so. We accordingly determine each of them to be prudent. In addition, no one opposes a determination that PSE's sale of the White River assets was reasonable. Again, PSE has presented evidence showing the reasonableness of its decision. We accordingly determine the sale was appropriate.

G. Satisfaction of Emissions Performance Standards

345 Washington state law requires that utilities comply with a greenhouse gas emissions performance standard (EPS)[438] and requires the Commission to enforce the standard with respect to electrical companies.[439] The EPS applies to long-term financial commitments that RCW 80.80.010(15) defines as:

> (a) Either a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility[440]; or
>
> (b) A new or renewed contract for baseload electric generation with a term of five or more years for the provision of retail power or wholesale power to end-use customers in this state.

346 We turn first to consideration of whether Sumas and Mint Farm satisfy the definition of baseload electric generation.

<u>*Baseload Generation*</u>

347 The Company presents evidence through Mr. Henderson to demonstrate that the Mint Farm Generating Station meets the statutory definition of baseload generation. Mr. Henderson says "Mint Farm was designed and intended to operate as a baseload

---

[438] RCW 80.80.040 and WAC 480-107-405.

[439] RCW 80.80.060.

[440] Baseload electric generation is defined as "Electric generation from a power plant that is designed and intended to provide electricity at an annualized plant capacity factor of at least sixty percent." RCW 80.80.010(4).

power plant."[441] He says that it is the Company's intent to operate the plant as a baseload plant in a manner similar to its operation of the Goldendale plant. Turning to the Sumas generating plant, Mr. Henderson says that it too is "currently designed and permitted as a baseload plant."[442] Mr. Henderson provides letters from the Department of Ecology (Ecology) to demonstrate that Ecology has concluded that both the Mint Farm and Sumas generating plants are baseload electric generation facilities subject to the EPS statute.[443]

348 Staff, through Mr. Nightingale, provides a detailed discussion about the operating characteristics of the Mint Farm generating plant and whether it qualifies as baseload generation. According to Mr. Nightingale, the Commission is required by the EPS statute to determine whether a plant qualifies as baseload after looking at:

1) The design of the power plant.

2) Its intended use, based upon:

   a. Permits necessary for the operation of the power plant.

   b. Any other matter the commission determines is relevant under the circumstances.[444]

349 Mr. Nightingale concludes that the key factors for the Commission to consider are "the design and the permits, and any similar operating characteristics such as technical capability limitations or legal operating restrictions."[445] He testifies that while the flexible characteristics of gas-fired generation plants allow modeled and actual operation to vary significantly from plant capability, it is more important to focus on evaluation of permit conditions and actual technical capability.[446]

350 Mr. Nightingale explains that the Mint Farm plant is a combustion turbine matched with a steam turbine that the manufacturer specifies has the capability to routinely

---

[441] Exhibit JMH-1T (Henderson) at 3:3-9.

[442] *Id.* at 4:18-5:6

[443] Exhibit JMH-5; Exhibit DN-2.

[444] Exhibit DN-1CT (Nightingale) at 39:16-40:2.

[445] *Id*. at 40:5-40:7.

[446] *Id.* at 41:8-42:6.

meet and exceed a 60 percent annualized capacity factor. He says that the relevant air permit issued by Ecology places no limitations on the number of hours during a year the plant can operate. Finally, he testifies that the Company has sufficient firm gas supply and gas transportation arrangements to operate the Mint Farm plant at or above a 60 percent capacity factor.[447]

351 Mr. Nightingale concludes that the Mint Farm plant qualifies as baseload generation because it is designed and permitted to operate at or above a 60 percent capacity factor.[448]

352 Mr. Norwood, for Public Counsel, does not dispute that the Sumas plant is baseload generation, but he contends that the Mint Farm plant does not appear to meet the definition because the Company's forecasts and models depicting actual use of the plant show capacity factors of 25 to 45 percent, significantly below the 60 percent requirement.[449] Public Counsel argues that the Company's actual operational data for Mint Farm demonstrates that it has not achieved a capacity factor of 60 percent since commencing operations and is not forecast to be operated in the rate year at more than 45 percent. He contends that the Company has admitted that it will operate the plant as baseload only if it is economical to do so.[450]

353 Public Counsel contends that it is not enough to meet the statutory definition of baseload for a power plant to be designed and permitted to operate at capacity factors of 60 percent or more. According to Public Counsel, the use of the term "intended" in the statute requires that actual operation of the facility be considered as a separate factor.[451] He argues that to not do so would violate the principles of statutory construction.

354 Turning to the air permit issued by the Department of Ecology, Public Counsel argues that it is not "determinative of intent." He says that the Commission, not Ecology, is given the authority to determine whether a plant qualifies as baseload.[452] Finally,

---

[447] Exhibit DN-1CT (Nightingale) at 42:12-44:17.

[448] *Id.* at 44:21-45:2.

[449] Exhibit SN-1HCT (Norwood) at 28:7-24.

[450] Public Counsel Initial Brief at ¶ 71.

[451] *Id.* at ¶¶ 68-71.

[452] *Id.* at ¶¶ 72-74.

Public Counsel argues that nothing in the air permit issued by Ecology verifies any intent for the plant to be operated at or above a 60 percent capacity factor.[453]

355 Staff disagrees with Public Counsel. Staff argues that the Commission must consider "intended use," but says that the statute directs the Commission to base that consideration on permits and other factors it determines to be relevant under the circumstances. Staff contends that in prior decisions the Commission has held that plant design is the primary focus.[454]

356 The Company argues further that Mr. Norwood's conclusion fails to consider Company testimony that "Mint Farm . . . is designed to run at a baseload capacity factor above 90 percent, and PSE intends to operate it in that matter whenever it is economically feasible to do so"[455] and ". . .Mint Farm, Sumas, and other combined-cycle plants . . . are designed to operate at capacity factors above 90%."[456] The Company argues that Mint Farms design capability and the lack of any limitations under its air permits demonstrate that it qualifies as baseload generation.[457]

357 *Commission Determinations:* No party challenges whether the Sumas facility qualifies as baseload generation and is therefore subject to the EPS requirements. The record contains the Company's assertion that the plant is capable of operating at the required capacity factor as well as evidence that the plant belongs to the class of combined-cycle turbines that were designed to achieve this performance. The record also includes Ecology's determination that the plant is baseload and must meet the EPS. While the latter is not determinative, because the law gives the authority to the Commission to make this judgment, it does add weight to the Company's own assertions. We determine that Sumas is baseload generation and must comply with the EPS.

358 Public Counsel's challenge to the classification of Mint Farm as baseload generation is based on the Company's modeling of plant operations and his interpretation of the EPS statute. Public Counsel acknowledges that the plant is designed to operate at a

---

[453] *Id.* at ¶ 25.

[454] Staff Reply Brief at ¶¶36-37.

[455] Exhibit WJE-1HCT (Elsea) at 51:16-19.

[456] Exhibit LEO-1CT (Odum) at 29:1-9.

[457] PSE Initial Brief at ¶¶ 26, 28.

capacity factor of 60 percent or more. However, his argument concerning "intended use" is wide of the mark. The fundamental intent of the RCW 80.80 is to ensure that new, or newly acquired, power generation facilities and long-term contracts do not emit greenhouse gases in excess of the EPS. To achieve this objective, the statute requires consideration of both design and intended use because neither factor by itself is sufficient. It would be inappropriate to allow a utility to circumvent the EPS simply by asserting that it intended to use a plant at less than 60 percent of its capacity, even though the design of the plant would accommodate more intensive operation if the utility's needs changed. It would also be inappropriate for the statute to allow for the special deferral treatment provided in RCW 80.80.060(6) if a utility argued it intended to use a plant at a capacity factor of 60 percent or more if the plant design, or air permits, will not allow such operation.

359 Public Counsel argues that the utility's forecasts and its flexibility in dispatch due to projected economics are determinative factors in judging whether a plant qualifies as baseload. This interpretation would allow utilities, or the Commission, to circumvent the EPS simply based on the strength of forecasts and uncertain conditions relating to economic dispatch. This is not a reasonable interpretation of the intent of the legislature. The more reasonable interpretation is that the design of a plant is the primary consideration, unless operations are specifically constrained by other factors, such as air permits.

360 There is no dispute about whether the Mint Farm combined cycle facilities are designed to operate at a capacity factor of 60 percent or more. There also is no constraint regarding the number of hours the plant is allowed to operate per year included in the air permit issued by the Department of Ecology.[458] We accordingly determine that the Mint Farm plant is baseload generation and is subject to the EPS and other provisions of RCW 80.80.

361 Having found both Sumas and Mint Farm meet the definition of baseload generation under RCW 80.80, we turn next to consideration of whether they comply with the EPS.

Compliance with the Emissions Performance Standard (EPS)

---

[458] Exhibit JMH-3.

362 RCW 80.80 establishes a greenhouse gases emission performance standard of no more than 1100 lbs. of carbon dioxide/MWh. The law states: "No electrical company may enter into a long-term financial commitment unless the baseload electric generation supplied under such commitment complies with the greenhouse gases emissions performance standard."[459] Commission rules require in relevant part that: "Electrical companies bear the burden to prove compliance with the greenhouse gases emissions performance standard under the requirements of WAC 480-100-415 as part of a general rate case."[460]

363 Mr. Henderson testifies that the Company provided detailed information to the Department of Ecology concerning the design and operation of both Sumas[461] and Mint Farm.[462] Ecology provided the Company with a letter verifying its determination that the Sumas generating plant is estimated to emit greenhouse gases at a rate of 951 lb/MWh and that Ecology believes the plant "should comply with the greenhouse gas emissions performance standard in WAC 173-407-130."[463] Ecology also provided the Company with a letter verifying its determination that the Mint Farm generating plant "will comply with the greenhouse gas emissions performance standard in WAC 173-407-130."[464]

364 Staff testifies that it has verified the methods and findings of Ecology that the plants will meet the standard.[465]

365 Public Counsel argues that for a power plant to comply with the EPS a utility must also show that it has need for the resource and the resource is appropriate. He points to both RCW 80.80.060(5) and WAC 480-100-415 and argues that the Company has not met these requirements with respect to Mint Farm. Public Counsel asserts that the Company does not need the plant to meet current capacity requirements and that less expensive resources were available that provided greater economic benefits.[466]

---

[459] RCW 80.80.060(1).

[460] WAC 480-100-405(1).

[461] *Id.* at 5:9-16 and Exhibit JMH-6.

[462] Exhibit JMH-1T (Henderson) at 3:12-21 and Exhibit JMH-4.

[463] Exhibit JMH-5 at 2 and Exhibit DN-2.

[464] Exhibit JMH-5 at 2.

[465] Exhibit DN-1HCT (Nightingale) at 18:20-20:6.

[466] Public Counsel Initial Brief at ¶¶ 59-60.

366 The Company counters that no provision in RCW 80.80.060 requires or mentions the need or appropriateness of a resource as criteria for determining EPS compliance.[467] Indeed, as Staff points out, RCW 80.80.060(5) no longer references the issues of resource need and appropriateness and even the prior version of the statute referenced those considerations only in the context of a Company application outside of a general rate case.[468]

367 Public Counsel acknowledges that the RCW 80.80.060 was amended effective July 2009 to remove the consideration of need and appropriateness from matters the Commission must consider, but he argues that the original accounting petition and the agreement among the parties to defer the matter to this general rate case predated the amendment to the statute. He also notes that the WAC 48-100-415 has not been amended to remover reference to resource need and appropriateness.[469]

368 *Commission Determination:* The Company has provided significant technical detail regarding plant emissions from both the Sumas and the Mint Farm facilities to the Commission and Ecology. After reviewing this information, Ecology concluded that both facilities meet the standard and Staff indicates that it has reviewed and verified Ecology's methods and findings. We are satisfied that both Sumas and Mint Farm will not exceed the statutory EPS.

369 Public Counsel's reference to the "need" and "appropriateness" criteria is to a version of the statute that is no longer current. Even if Public Counsel's references to these criteria were relevant, they are not applicable because the prior statute only required consideration of these factors in the case of a company's application for determination of compliance with the EPS outside of a general rate case. WAC 480-100-405 only requires that the information included in an application made as part of a general rate case include the same categories of information required for an application outside of a general rate case. In any event, we determine elsewhere in this Order that PSE's acquisitions of Sumas and Mint Farm were prudent, thus establishing them as resources that were both needed and appropriate.

---

[467] PSE Initial Brief at ¶ 24.

[468] Staff Reply Brief at ¶ 33.

[469] Public Counsel Initial Brief at ¶ 23.

FINDINGS OF FACT

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

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

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

373 (3) The following investments by PSE were prudent and were made at reasonable costs:

- Acquisition of the Mint Farm Energy Center.
- Purchase of Fredonia Generating Units 3 and 4.
- Expansion of the Wild Horse Wind Facility to add 44 MW of capacity to the facility.
- Execution of a four-year winter power purchase agreement with Barclays Bank PLC.
- Execution of a four-year and three-month power purchase agreement with Credit Suisse.
- Execution of a five-year power purchase agreement with Puget Sound Hydro LLC.
- Execution of a five-year power purchase agreement with Qualco Energy, LLC.

- Execution of a five-year power purchase agreement with Powerex for Point Roberts.

PSE's sale of the White River Assets to the Cascade Water Alliance was reasonable and appropriate.

374 (4) The Mint Farm and Sumas CCCT plants are baseload generation within the meaning of RCW 80.80. They are subject to, and satisfy, the Emissions Performance Standard established by RCW 80.80.040.

375 (5) PSE, having revised its initial proposal for increased rates during the course of this proceeding, did not show the rates proposed by tariff revisions filed on May 8, 2009, and suspended by prior Commission order, to be fair, just, or reasonable.

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

377 (7) The record in this proceeding supports a capital structure and costs of capital, which together produce an overall rate of return of 8.10 percent, as set forth in the body of this Order in Table 11.

378 (8) The Commission's resolution of the disputed issues in this proceeding, coupled with its determination that certain uncontested adjustments are reasonable, result in finding that PSE's natural gas revenue deficiency is $10,149,229 and its electric revenue deficiency is $56,204,849, subject to adjustment to reflect recalculation of the Tenaska and March Point disallowances and the production factor adjustment, as discussed in the body of this Order.

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

380 (10) The terms of the multiparty settlements concerning electric and natural gas rate spread and rate design, respectively attached to this Order as Appendices

A and B, and incorporated by this reference, are consistent with the public interest.

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

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

CONCLUSIONS OF LAW

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

384 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

385 (2) The rates proposed by tariff revisions filed by PSE on May 8, 2009, and suspended by prior Commission order, were not shown to be fair, just or reasonable and should be rejected.

386 (3) PSE's existing rates for electric service and natural gas service provided in Washington State are insufficient to yield reasonable compensation for the service rendered.

387 (4) PSE requires relief with respect to the rates it charges for electric service and natural gas service provided in Washington State.

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

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

390 (7) PSE should have the opportunity to earn an overall rate of return of 8.10 percent based on the capital structure and costs of capital set forth in the body of this Order, including a return on equity of 10.10 percent on an equity share of 46.00 percent.

391 (8) PSE should be authorized and required to make a compliance filing to recover its revenue deficiency of $10,149,229 for natural gas service. PSE should be authorized, subject to Staff review and Commission approval, to adjust the $56,204,849 revenue deficiency found under the determinations in this Order to be its approximate revenue requirement for electricity to account for recalculation of the Tenaska and March Point 2 disallowances and the production factor adjustment and should be authorized and required to make a compliance filing to recover the adjusted revenue deficiency for electric service.

392 (9) PSE should be authorized and required to recover the portion of its electric revenue requirement that is associated with the Tenaska regulatory asset via a separate tariff rider with a class-specific kWh rate sufficient to recover these costs for the duration of the amortization period, but with a sunset, or ending date, of December 31, 2011. Base rates determined in this proceeding should be reduced by the revenue requirement amount reflecting the separate treatment of the Tenaska-related costs.

393 (10) The multiparty settlements concerning electric and natural gas rate spread and rate design, respectively attached to this Order as Appendices A and B, and incorporated by prior reference, should be approved and adopted.

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

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

396 (13) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

397 (14) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS THAT:

398 (1) The proposed tariff revisions PSE filed on May 8, 2009, which were suspended by prior Commission order, are rejected.

399 (2) The multiparty settlements concerning electric and natural gas rate spread and rate design, respectively attached to this Order as Appendices A and B, and incorporated into this Order by prior reference, are approved and adopted.

400 (3) PSE is authorized and required to file tariff sheets following the effective date of this Order that are necessary and sufficient to effectuate its terms. The required tariff sheets must be filed at least two business days prior to their stated effective date, which shall be no sooner than April 7, 2010.

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

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

Dated at Olympia, Washington, and effective April 2, 2010.

WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

JEFFREY D. GOLTZ, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

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

APPENDIX A

MultiParty Settlement Agreement - Electric Rate Spread, Rate Design

APPENDIX B

MultiParty Settlement Agreement - Natural Gas Rate Spread, Rate Design