

Exhibit No. ___CT (APB-1CT)
Docket UE-1111048/UG-111049
Witness: Alan P. Buckley
Redacted Version

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.,

Respondent.

DOCKET UE-111048
DOCKET UG-111049
(Consolidated)

TESTIMONY OF

ALAN P. BUCKLEY

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Power Supply Issues

December 7, 2011

CONFIDENTIAL PER PROTECTIVE ORDER
Redacted Version

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LIST OF EXHIBITS

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| Exhibit No. __ (APB-2) | Summary of Proposed Adjustments |
| Exhibit No. __ (APB-3) | PSE Response to Staff Data Request 161 |
| Exhibit No. __ (APB-4C) | Mills and Story Workpaper Excerpts |
| Exhibit No. __ (APB-5C) | Mills Workpaper Excerpt and Staff Update |
| Exhibit No. __ (APB-6) | PSE Response to ICNU Data Request 2.80 and 2.82 |
| Exhibit No. __ (APB-7) | Mills Workpaper Excerpt |
| Exhibit No. __ (APB-8C) | Mills Workpaper Excerpt and PSE Response to ICNU Data Request 5.10 |
| Exhibit No. __ (APB-9C) | Mills Workpaper with Staff Notation |

1 I. INTRODUCTION

2

3 **Q. Please state your name and business address.**

4 A. My name is Alan P. Buckley. My office address is The Richard Hemstad Building,
5 1300 South Evergreen Park Drive Southwest, P.O. Box 47250, Olympia,
6 Washington 98504. My email address is abuckley@utc.wa.gov.

7

8 **Q. By whom are you employed and in what capacity?**

9 A. I am employed by the Washington Utilities and Transportation Commission
10 (“Commission”) as a Senior Policy Strategist. Among other duties, I am responsible
11 for analyzing rate and power supply issues as they pertain to the investor-owned
12 electric utilities under the jurisdiction of the Commission.

13

14 **Q. How long have you been employed by the Commission?**

15 A. I have been employed by the Commission since 1993.

16

17 **Q. Would you please state your educational and professional background?**

18 A. I received a Bachelor of Science degree in Petroleum Engineering with Honors from
19 the University of Texas at Austin in 1981. In 1987, I received a Masters of Business
20 Administration degree in Finance from the University of California at Berkeley.

21 From 1981 through 1986, I was employed by Standard Oil of Ohio (now
22 British Petroleum-America) as a Petroleum Engineer working on Alaskan North
23 Slope exploration drilling and development projects. From 1987 to 1988, I was

1 employed as a Rates Analyst at Pacific Gas and Electric Company. I was next
2 employed by R.W. Beck and Associates, an engineering and consulting firm in
3 Seattle, Washington, conducting cost-of-service and other rate studies, carrying out
4 power supply studies, analyzing mergers, and analyzing the rates of the Bonneville
5 Power Administration (“BPA”) and the Western Area Power Administration.

6 I came to the Commission in December 1993, where I have held a number of
7 positions including Utility Analyst, Electric Program Manager, and the position that I
8 now hold. I have been a witness in numerous proceedings before the Commission,
9 including several general rate cases of Puget Sound Energy, Inc. (“PSE” or the
10 Company”) in which I testified on power supply issues. I also have testified before
11 BPA and the Federal Energy Regulatory Commission.

12 13 II. SCOPE AND ORGANIZATION OF TESTIMONY

14
15 **Q. What is the purpose of your testimony?**

16 **A.** The purpose of my testimony is to address the proposed rate year power costs for the
17 period May 2012 through April 2013, as presented in PSE’s General Rate Case filed
18 on June 13, 2011 and updated on September 1, 2011. I will also address certain
19 production operations and maintenance expenses that are included in the testimony
20 of Company witness Mr. David E. Mills.

21 The Company’s proposed updated rate year power costs of \$982.8 million
22 represent an approximate \$9.6 million decrease from the originally filed power costs
23 of \$992.5 million, and a \$97.8 million decrease from amounts set in current rates. In

1 Exhibit No. ___ (APB-2), I provide a summary of my recommended adjustments to
2 the Company's proposed rate year power costs at the expense level. The results of
3 these adjustments on revenue requirement are reflected in Staff witness Martin's
4 Exhibit No. ___ (RCM-2).
5

6 **Q. How is the remainder of your testimony organized?**

7 A. The remainder of my testimony is divided into three sections. In Section III, I
8 discuss the overall context for evaluating the Company's proposed rate year power
9 costs. In Section IV, I summarize my recommended adjustments to the Company's
10 proposed rate year power costs, including certain production O&M and transmission-
11 related costs. In Section V, I explain the basis for each adjustment and describe the
12 method of calculating the adjustment amount.
13

14 **Q. Did you prepare any exhibits in support of your testimony?**

15 A. Yes. They are the following:

- 16 • Exhibit No. ___ (APB-2), Summary of Staff's Net Power Cost Adjustments
- 17
- 18 • Exhibit No. ___ (APB-3C), PSE Response to Staff Data Request 161
- 19
- 20 • Exhibit No. ___ (APB-4C), Mills and Story Workpaper Excerpts
- 21
- 22 • Exhibit No. ___ (APB-5C), Mills Workpaper Excerpt and Staff Update
- 23
- 24 • Exhibit No. ___ (APB-6), PSE Response to ICNU Data Request 2.80 and 2.82
- 25
- 26 • Exhibit No. ___ (APB-7), Mills Workpaper Excerpt
- 27

- 1 • Exhibit No. __ (APB-8C), Mills Workpaper Excerpt and PSE Response to
2 ICNU Data Request 5.10
- 3
- 4 • Exhibit No. __ (APB-9C), Mills Workpaper with Staff Notation
- 5

6 III. CONTEXT OF POWER COST EVALUATION

7

8 **Q. Please describe the overall context in which you evaluated PSE's proposed rate**
9 **year power costs in this proceeding.**

10 A. In evaluating the Company's proposed rate year power costs, I recognized several
11 important factors relevant to this proceeding. These factors are:

- 12 1) PSE appears to be in a period of falling-to-stable gas and electric market prices
13 with less volatility, at least as compared to the past few years;
- 14 2) the Company operates with a comprehensive power costs adjustment ("PCA")
15 mechanism with annual filings that account for the differences between PSE's actual
16 power costs and a power cost baseline; and
- 17 3) Docket UE-111048 continues PSE's recent trend of annual general rate case
18 filings, in addition to the Company's regular annual PCA filings.¹

19

20 **Q. Why are these factors important in evaluating proposed rate year power costs**
21 **in general rate case proceedings?**

22 A. Rate year power costs are generally developed using a combination of production
23 cost modeling techniques and non-modeled rate year expense or revenue projections

¹ The PCA Mechanism is an annual accounting process to share costs and benefits between PSE and its customers over four graduated levels for the first \$120 million of power cost variances. For power cost variances over \$120 million, the PCA sharing mechanism allocates 95 percent of costs or benefits to customers and the remaining 5 percent of costs or benefits to PSE.

1 that are derived from normalized data or budgeted amounts. Actual contracted
2 transactions in place during the rate year are incorporated into the proposed power
3 costs. Both modeled and non-modeled costs and revenues are highly dependent on
4 price projections for both the gas and electric markets.

5 I believe the factors identified above affect the appropriate and practical
6 robustness of expense projections, including how they may be approached from a
7 cost recovery standpoint. For example, if certain variable costs are tracked and
8 potentially recovered through a PCA, the Commission may choose not to incorporate
9 relatively uncertain or unsupported projections of expenses when determining the
10 appropriate rate year power costs to include in base rates. Expense projections that
11 lack full support should not be allowed. This approach can also be followed when a
12 company has a track record of repeated general rate case filings in which base rates
13 are regularly adjusted. In fact, in my opinion, a history of regular general rate cases
14 raises the question of whether annual PCAs are appropriate in the first instance. One
15 of the fundamental goals of a PCA, that is, lessening the administrative burden on
16 the Commission and parties in evaluating utility rate filings, is not being met.

18 IV. SUMMARY OF STAFF RECOMMENDATIONS

19
20 **Q. Please summarize your recommended adjustments to the Company's proposed**
21 **pro forma normalized net power costs.**

22 A. Exhibit No. ___ (APB-2) identifies each of these adjustments I recommend with the
23 corresponding estimated expense level impact. The total expense level adjustment

1 reduces rate year power costs by an estimated \$23,937,941. This amount is expected
2 to increase significantly as rate year forward gas prices have continued to fall. The
3 exact level of the reduction depends on incorporating the non-modeled adjustment
4 amounts with the modeled power cost amounts after any Commission-ordered
5 market price update that occurs at the end of a rate case.

6 Most of the adjustments shown on Exhibit No. ___ (APB-2) are calculated
7 without running the AURORA model and are considered “not-in-model”
8 adjustments. Although Staff has access to the AURORA model used by PSE, I did
9 not carry out AURORA model runs to derive the expense levels for the market price
10 update adjustment, relying instead on a rough estimate of its effect on rate year
11 power costs. I recommend the Commission order PSE to carry out the appropriate
12 AURORA model runs, including any Commission-ordered adjustments, as part of
13 the Company’s rate case compliance filing. This procedure will insure that the effect
14 of all accepted adjustments is captured for ratemaking purposes.

15

16 **V. NET POWER COST ADJUSTMENTS**

17

18 **A. Production O&M – Non Contract Major**

19

20 **Q. What is the context of your first adjustment, labeled “Production O&M – Non**
21 **Contract Major” in Exhibit No. ___ (APB-2)?**

22 **A.** This adjustment normalizes non-contract, major production O&M expenses for
23 PSE’s gas fired resources. The Company proposes to include [REDACTED] million in total

1 production-related operating and maintenance expense for the rate year. Exhibit
2 No. ___(DEM-7C), page 2, line78. This is a significant increase from the 2009
3 general rate case production O&M costs of [REDACTED] million.

4 PSE identifies major maintenance expenses for units without contracts as one
5 of the drivers for these increased expense levels. Included in the [REDACTED] million
6 proposal is approximately \$8.2 million associated with non-contract major
7 maintenance of certain gas fired turbines. These units and their proposed O&M
8 expenses are individually identified in Exhibit No. ___(APB-3), which is the
9 Company's response to Staff Data Request No. 161.

10 PSE proposes to simply use the historical test year expense levels for each of
11 the units, even though it is apparent that the units have experienced significant
12 variability in non-contract major O&M costs over the past years. For example, as
13 the Company's response to Staff Data Request No. 161 indicates, Fredonia Units 1-4
14 have experienced annual non-contract O&M costs ranging from zero to \$1.8 million
15 during the last six years. Nevertheless, the Company's proposal uses the \$1.8
16 million expense level, which was the 2010 test year amount.

17 Clearly, the actual non-contract O&M expenses all vary significantly and do
18 not have a discernable trend. It is clear from the actual historical non-contract major
19 O&M expenses that the simple use of test year amounts is inappropriate and
20 excessive. There is a clear pattern of normal variability in the non-contract O&M
21 expense related to these gas-fired units and, therefore, a rate year expense level based
22 on a wider range of actual historical expenses should be used.

1 **Q. What is your proposed adjustment to the non-contract O&M levels included as**
2 **rate year amounts by the Company?**

3 A. My adjustment uses the 5-year average non-contract O&M expense levels for the
4 rate year. Although Exhibit No. ___(APB-3) shows six years of historical expense
5 levels, I use only the latest five years of data.

6
7 **Q. How did you calculate your proposed adjustment?**

8 A. I averaged the total non-contract O&M expenses for the years 2006 through 2010 to
9 derive a 5-year average of \$4.66 million, as shown in Exhibit No. ___(APB-3). I
10 then compared that to the \$8.2 million Company-proposed level for the rate year.

11
12 **Q. What is the amount of your proposed Production O&M adjustment to the**
13 **Company's proposed pro forma normalized net power costs?**

14 A. My proposal results in a \$3.54 million adjustment to rate year Production O&M.
15 This lowers the overall proposed rate year Production O&M level to \$134.06
16 million, not including other proposed production O&M expenses adjustments. These
17 figures are at the expense level.

18
19 **B. BPA Transmission Service Credit**

20
21 **Q. Your next adjustment is labeled "BPA Transmission Service Credit" in Exhibit**
22 **No. ___ (APB-2). Please explain the context of this adjustment.**

1 A. This adjustment recognizes additional revenue credits that will occur as a result of a
2 startup date of the Lower Snake River wind project (“LSR”) that is earlier than first
3 expected. The Company has included various costs related to LSR for the rate year.
4 Among these costs is the fixed and variable transmission expenses associated with
5 BPA transmission service from LSR.

6

7 **Q. How did the Company calculate its adjustment?**

8 A. For purposes of proposed rate year transmission expenses, the Company included
9 fixed costs beginning in May 2012, as shown on Lines 131 through 156 of page 1,
10 Exhibit No. ___(APB-4C). Exhibit No. ___(APB-4C) contains three pages of
11 workpapers from Company witnesses Mills and Story related to certain LSR costs.
12 Page 2 of Exhibit No. ___(APB-4C) also shows that the Company included the
13 energy from LSR in the development of normalized power costs derived from the
14 AURORA model.

15 However, the Company, in neither the original filing nor the supplemental
16 filing, included the return of LGIA - Customer Interest on Prepaid Transmission until
17 the LSR startup date, which was assumed to be August 2012, as shown on page 1 of
18 Exhibit No. ___(APB-4C). This amount relates to a return of monies through a credit
19 to the overall BPA transmission expense associated with PSE’s financing of certain
20 BPA transmission facilities. Surprisingly, unlike LSR energy and transmission costs,
21 the resulting credit is applied only on a nine-month basis in the Company’s
22 adjustment.

23

1 **Q. Please describe your BPA Transmission Service Credit adjustment.**

2 A. It is Staff's understanding that the startup date for LSR has been moved up several
3 months, so that it will now be in service for the entire rate year. Consistent with that
4 information and the fact that the energy and transmission costs were already included
5 on an annual basis in the rate year calculation of proposed net power costs, I adjusted
6 the LGIA - Customer Interest on Prepaid Transmission on a full twelve-month basis.

7
8 **Q. How did you calculate your adjustment?**

9 A. Page 3 of Exhibit No. ___ (APB-4C) shows estimated BPA Transmission Service
10 credit amounts from April 30, 2012 through August 31, 2015, as obtained from the
11 non-confidential workpapers of Company witness Story. (Story Workpapers 5.03E,
12 "Bill Credits" tab) My adjustment for the earlier startup date of LSR is obtained by
13 summing the indicated amount for the months May 2012 through July 2012 and
14 including that amount as an additional credit to the amount shown on Page 1 of
15 Exhibit No. ___ (APB-4C): LGIA - Customer Interest on Prepaid Transmission.

16
17 **Q. What is the amount of your proposed BPA Transmission Service credit
18 adjustment to the Company's proposed rate year power costs?**

19 A. The additional credit reduces overall proposed rate year transmission expense
20 included in power costs by \$843,700. This figure is at the expense level.

21

22

1 C. **MTM Base Line**

2

3 Q. **Your next adjustment is labeled “MTM Base Line” in Exhibit No. __ (APB-2).**

4 **Please explain the context of this adjustment.**

5 A. This adjustment removes from the determination of base power costs certain

6 expenses associated with fixed price gas hedges. As part of its proposed rate year

7 power costs, PSE includes what is called “mark-to-market” (“MTM”) costs.

8 Generally, this expense relates to the difference between the market price of gas

9 throughout the rate year and the price paid for actual forward gas contracts that have

10 been entered into for the rate year. The Company has included these costs as a rate

11 year expense due to the fact that the production cost dispatch model used to develop

12 rate year power costs is dispatched based on the market price of gas and electricity

13 forecast during the rate year, not the actual price that may have been paid under an

14 existing forward contract for the period. The mark-to-market calculation may result

15 in an expense or revenue adjustment, depending on the relationship of the rate year

16 forward fixed contract price and the forecast market price for the rate year.

17

18 Q. **What are the differences between your adjustment and the Company’s?**

19 A. The Company’s mark-to-market expense shown on Page 1, Exhibit No. __ (DEM-

20 7C), line 61, includes approximately [REDACTED] million in rate year credits that are more

21 accurately described in Mr. Mill’s testimony (Exhibit No. __ (DEM-1CT), page 55,

22 line 1 through page 56, line 8) as a “basis differential adjustment” related to the

23 Company’s contracted rights on Westcoast pipeline. The mark-to-market expense at

1 issue in my testimony relates to those amounts included as expenses due primarily to
2 fixed futures contracts for Sumas gas and a much smaller amount tied to gas
3 acquired from the Cedar Hills Landfill project in King County.

4 The mark-to-market expense related to Cedar Hill's gas is discussed later in
5 my testimony. The adjustment identified as MTM Base Line addresses the market-
6 to-market expense identified as "Fixed at Sumas" transactions in the Company's
7 workpapers. Page 1 of Exhibit No. ___ (APB-5C) contains the confidential tab
8 labeled "Summary Gas MTM" from Mr. Mill's Workpaper DEM-WP(C) Gas MTM
9 2011GRC Update. That workpaper shows the amounts related to the "Fixed at
10 Sumas" MTM expenses from the Company's supplemental filing, as well as the
11 annual amount contained in the original filing. As indicated, a slight increase in the
12 rate year gas price forecast used by the Company resulted in a decrease in the "Fixed
13 at Sumas" MTM expense from approximately [REDACTED] million to [REDACTED] million. This
14 decrease was due to a slight increase in forecast rate year gas prices between the two
15 filings. However, forecast rate year gas prices have decreased significantly since the
16 supplemental filing. Page 2 of Exhibit No. ___ (APB-5C) is a Staff updated version
17 of the same workpaper showing the effect on the "Fixed at Sumas" MTM amount
18 based on more recent three-month averages of forecast rate year gas prices. Due to
19 the decrease in those forecast rate year gas prices, the "Fixed at Sumas" MTM
20 expense has increased significantly to an estimated [REDACTED] million. This expense
21 amount will continue to change as forecast rate year gas prices evolve throughout the
22 proceeding. Page 3 of Exhibit No. ___ (APB-5C), again a Staff update of a Company

1 workpaper, shows the monthly November 16, 2011, 3-month rolling average gas
2 price forecast used by Staff.

3
4 **Q. What issues do you have regarding the MTM Sumas Hedge expense proposed**
5 **by the Company?**

6 A. My issues are twofold. First, as indicated in Exhibit No. ___ (APB-5C), the actual
7 expense amounts projected for determining rate year power costs varies significantly
8 throughout the rate proceeding as forecast gas prices change. This questions the
9 validity of any amount under the “known and measurable” standard for pro-forma
10 adjustments. In actuality, the true costs of any fixed price gas hedges entered into by
11 the Company are not known until the rate period passes.

12 Second, it is inappropriate for purposes of setting a base power supply level
13 to include the cost associated with hedging more gas volumes than are actually used
14 in the development of normalized power costs.

15
16 **Q. What options are available to address your issues regarding MTM Sumas**
17 **Hedge expenses?**

18 A. There are several possible solutions. First, the Commission could remove the MTM
19 Sumas Hedge expense entirely from rate year power supply expense levels and rely
20 instead upon the Company’s PCA to recover actual mark-to-market costs at the
21 appropriate levels, should they actually occur during the rate year. Based on the
22 supplemental filing with no additional price updates, this would result in a reduction
23 of rate year power costs of approximately [REDACTED] million for purposes of setting base

1 rates. This solution, however, creates some inconsistencies between the recovery of
2 hedge cost expenses and the benefits of including the effect of declining forecast rate
3 year gas prices in base rates.

4 The other solution is for the Commission to continue to order updates at the
5 latest possible stage in any proceeding that would incorporate rate year gas and
6 electric price forecasts used to develop proposed net power supply costs. However,
7 sufficient time should be allowed for the parties to review any such update.

8 Finally, as explained next, my proposed adjustment addresses the MTM
9 Sumas Hedge expenses by allowing in base rates only the appropriate mark-to-
10 market volumes. This is a partial, but valid, response to the issue of uncertain and
11 changing MTM Sumas Hedge expenses.

12
13 **Q. How do you propose to address the issue of uncertain and changing MTM**
14 **Sumas Hedge expenses?**

15 A. As a balanced and conservative response, I remove an estimated percentage of MTM
16 Sumas Hedge costs associated with hedged gas volumes that are greater than the gas
17 volumes actually used by the Company in its production cost model to determine
18 normalized power costs.

19 This MTM Base Line adjustment would only affect the power supply
20 expense level used for determining base rates, in that, the Company, through the
21 PCA, is given the opportunity to recover additional costs or benefits from hedged gas
22 volumes greater than what was used to determine normalized power costs. In
23 addition, treating those additional volumes through the PCA allows the Commission

1 to better match the costs and benefits associated with the additional levels of
2 secondary sales transactions actually made by PSE above those levels used to
3 determine normalized net power costs. Presumably, the Company entered into gas
4 hedge volumes greater than shown necessary by the normalized production cost
5 model runs in order to support some future energy transactions position above and
6 beyond what was included in setting base rates. The treatment of at least a portion
7 mark-to-market related amounts in the PCA is also appropriate as, over time, any
8 such adjustments should balance.

9
10 **Q. How did you calculate your MTM Base Line adjustment?**

11 A. I compared the volumes shown in Exhibit No. ___ (APB-5C) for the MMBTUs of
12 gas fixed at Sumas to the total volume of gas utilized in the Company's supplemental
13 AURORA production cost model run. The Company's gas fired resources utilized a
14 normalized [REDACTED] MMBTUs of gas, according to the Company workpapers
15 (DEM-WP(C) Power Cost Summary 2011 GRC Update Workpaper, Tab: "Gas
16 Turbine"). Based on the "Fixed at Sumas" gas volumes in page 1 of Exhibit
17 No. ___ (APB-5C), the Company has already hedged [REDACTED] MMBTUs of Sumas
18 gas alone for the rate year. This results in an excess hedge volume of 1,915,477
19 MMBTUs on an annual basis solely based on Sumas volumes.

20 To calculate my MTM Base Line adjustment, I used the ratio of excess
21 volumes to total fixed hedged Sumas volumes, applied to the total annual "Fixed at
22 Sumas" MTM expense of [REDACTED] as shown on page 1 of Exhibit No. ___ (APB-
23 5C). This calculation is based on annual averages. The adjustment is also based on

1 gas prices from the Company's supplemental filing. My adjustment will increase
2 significantly with more recent lower forward gas price projections as MTM expenses
3 increase correspondingly. Therefore, my adjustment will have to be recalculated as
4 part of any compliance filing.

5 Another methodology, equally as valid, would be to use monthly volumes
6 and prices, in which gas volume applicable to mark-to-market volumes would be
7 limited to those monthly volumes equal to or less than the monthly volumes from the
8 normalized AURORA production cost model.

9

10 **Q. What is the amount of your MTM Base Line adjustment to the Company's**
11 **proposed rate year power costs?**

12 A. The MTM Base Line adjustment (using supplemental filing and not updated for the
13 more current forward gas price projections) reduces rate year power supply expenses
14 by \$1,264,732. This figure is at the expense level.

15

16 **D. Wind Integration Cost Treatment**

17

18 **Q. Your next adjustment is labeled "Wind Integration Cost Treatment" in**
19 **Exhibit No. __ (APB-2). Please explain the context of this adjustment**

20 A. This adjustment removes uncertain and non-measurable internal wind integration
21 costs and moves any recovery of actual costs to the PCA. The Company proposes to
22 recover in base rates two general categories of wind integration costs – those wind
23 integration costs paid to BPA and those identified as internal wind integration costs.

1 Wind integration costs, in general, have been an issue in all recent general rate cases.
2 For those Company wind resources locating in the BPA Balancing Authority, PSE
3 pays BPA a fixed rate based on the capacity of the projects. The rate applicable for
4 the rate year is being set through a combined BPA power and transmission rate
5 proceeding to set new rates for fiscal year 2012-2013. PSE's Hopkins Ridge,
6 Klondike III, and the new LSR projects are all located within the BPA Balancing
7 Authority. PSE's Wild Horse project, including the expansion, is located within the
8 PSE Balancing Authority.

9

10 **Q. How does PSE integrate wind projects within its balancing authority?**

11 A. To address the divergence in actual generation output, the Company uses generation
12 from its Mid-C hydro resource, with its Automatic Generation Control ("AGC") and
13 other generating resources. The Company states that: "For most of the year, PSE's
14 average annual 726 MW share of Mid-C hydro generation may be sufficient to
15 manage the instantaneous load and Wild Horse wind generation variability and any
16 deviations from their respective schedules." (Exhibit No. ___ (DEM-1CT), page 25,
17 lines 3 through 6) PSE goes on to say that there are times that Mid-C flexibility may
18 not be available, such as during Spring runoff and that other thermal resources or
19 market transactions must be used to balance the system:

20 PSE takes a least cost approach to integrating wind, which first utilizes its
21 Mid-C hydro assets to ensure adequate balancing reserves. If constraints
22 limit the flexibility of the Mid-C and market transactions are not available,
23 then PSE's most efficient thermal resources are called upon to provide any
24 remaining balancing capacity. PSE must also hold capacity in reserve for the
25 day-ahead timeframe for all of its wind resources, as this service it not
26 offered by BPA.

27

1 Exhibit No. ___ (DEM-1CT), page 29, lines 1 through 6.

2

3 **Q. How has the Company determined its proposed rate year internal wind**
4 **integration costs?**

5 A. PSE completed a study of the costs to integrate wind resources by studying the
6 impact on generation and load regulation attributable to incremental wind generation
7 in its balancing authority. The Company divided its proposed internal wind
8 integration costs into those related to “day-ahead” integration and those related to
9 “within-hour” integration costs. These costs are shown in Table 6 on page 29 of
10 Exhibit No. ___ (DEM-CT).

11

12 **Q. Please summarize your proposed adjustment to wind integration costs.**

13 A. I remove from the determination of rate year net power costs used to develop base
14 rates for PSE, the proposed costs associated with day-ahead wind integration for all
15 PSE owned wind projects and the within-hour wind integration costs for the Wild
16 Horse and the Wild Horse Expansion wind projects. It is important to emphasize that
17 I remove only these costs for use in determining rate year base rates, as any actual
18 costs that are occurred in providing both day-ahead and within-hour wind integration
19 will be captured through the PCA, if they actually occur. Actual power supply costs
20 or benefits, whether it is Company resource-related or market transaction-related,
21 necessary to balance wind and load, will be included in the PCA. Any realized lost
22 opportunity costs will be captured through the PCA. In this manner, the unknown
23 and variable wind integration costs (or benefits) will be treated in the same manner
24 as actual variations in fuel costs, market prices, and load for purposes of recovery.

1 There is simply too much uncertainty in wind integration costs to warrant their
2 inclusion in base rates when a PCA mechanism is available.

3

4 **Q. Would your recommendation be appropriate if PSE operated without a PCA?**

5 A. No. In a regulatory rate making environment without a power cost adjustment
6 mechanism it may be appropriate to estimate some rate year net costs associated with
7 integrating wind resources. However, when a power cost adjustment mechanism is
8 in place, it is not necessary to do so.

9

10 **Q. What is the basis for your recommendation?**

11 A. As testified by the Company, the Mid-C hydro resource can be used to balance any
12 variation between scheduled and actual generation, should that occur. The wind
13 integration costs projected by PSE for the rate year are estimated costs using
14 assumptions regarding the opportunity costs of reserving capacity to meet wind
15 schedule deviation. In actuality, the variations are similar to normal variations in
16 load that occur every hour and are addressed using the Company's Mid-C hydro
17 resource and other resources with AGC. Exhibit No. ___ (APB-6) contains the
18 Company's responses to ICNU Data Requests 2.80 and 2.82. The response to ICNU
19 Data Request 2.80 states that PSE has not been able to determine its actual day-ahead
20 wind integration costs during 2009 and 2010, and in fact, does not have the means to
21 do so. There is no evidence that PSE loses any "day-ahead" opportunity.

22 In addition, as indicated in the response to ICNU Data request 2.82, the costs
23 associated with providing day-ahead wind integration of LSR are developed using

1 characteristics of another wind project. This adds another level of uncertainty to the
2 validity of the proposed costs.

3 Finally, the Company's proposed amount related to within-hour wind
4 integration also lacks sufficient robustness for inclusion in rate year net power costs.
5 I recognize that certain costs associated with wind integration may occur. However,
6 those costs do not rise to a sufficient level of certainty to warrant inclusion in rate
7 year power costs for purposes of setting base rates.

8
9 **Q. Will the PCA mechanism provide the Company an opportunity to recover**
10 **internal wind integration costs should they occur?**

11 A. Yes. The actual internal costs to integrate wind, including benefits of the sale of
12 excess wind generation over scheduled amounts, ultimately manifests itself through
13 variations in purchased power cost, power sales revenues, and the various actual
14 resource costs on an hourly basis. This includes any variations that may occur
15 through "lost opportunity." These amounts are tracked in the PCA and treated
16 accordingly. In effect, ratepayers are responsible only for the costs that actually
17 occur.

18
19 **Q. How did you calculate your adjustment?**

20 A. I removed the "Not in AURORA" Wind Integration Costs from the determination of
21 rate year net power supply expense. This rate year expense item represents the
22 amount proposed by the Company to recover what it has identified as internal wind

1 integration costs. The Company continues to recover the estimated \$9.5 million in
2 wind integration costs to be paid to BPA.

3

4 **Q. What is the amount of your Wind Integration Cost Treatment adjustment to**
5 **the Company's proposed rate year power costs?**

6 A. Removing the day-ahead wind integration cost related to all PSE wind projects
7 reduces rate year power costs by \$2,516,579, while removing the "within-hour"
8 proposed amount related to Wild horse and the Wild Horse Expansion reduces rate
9 year power costs an additional \$2,869,431, or \$5,386,010 total. These figures are at
10 the expense level. For illustrative purposes, the \$5.4 million adjustment represents
11 only 0.64 percent of the overall \$843.8 million rate year, non-production O&M
12 related power costs proposed by the Company.

13

14 **E. Transmission Capacity**

15

16 **Q. Your next adjustment is labeled "Transmission Capacity" in Exhibit No. __**
17 **(APB-2). Please provide the context of this adjustment.**

18 A. The adjustment removes an unsupported transmission expense item. On page 15 of
19 Exhibit No. __ (DEM-1CT), the Company discusses changes to PSE's transmission
20 capacities for the rate year. Mr. Mills explains that the Company has chosen to
21 renew a 23MW firm capacity contract with BPA that was previously related to the
22 transmission of power from a City of Spokane Municipal Steam Waste project and
23 that expires on December 31, 2011. The cost of power from that project was

1 included previously in the determination of the Company's net power costs. The
2 existing contract was renewed at a rate year cost of \$414,000. To support the
3 renewal the Company states simply that: "PSE has increased its ability to purchase
4 short-term resources at the Mid-C trading hub and reduced its transmission capacity
5 need by 23 MW starting in 2012." (Exhibit No. ___(DEM-1CT), page 15, lines 11 -
6 13). No quantification of the benefits was included by the Company. Absent the
7 need for the Company to move power from the City of Spokane project, PSE has
8 made no explicit showing of benefits, or reduced costs, related to the acquisition of
9 this firm transmission capacity.

10
11 **Q. Please describe the rationale for your Transmission Capacity adjustment.**

12 A. The incremental acquisition of firm transmission capability should be supported by a
13 showing of firm benefits at least equal to the annual cost of the expense. The
14 Company has failed to make that showing, relying instead on the general claims
15 cited above. This is clearly not a showing that sufficient margins from sales, or
16 decreases in costs, have occurred to support the expense amount, particularly for the
17 acquisition of firm transmission capacity. The costs associated with this BPA firm
18 transmission service should be removed or, correspondingly, an equal amount of
19 identifiable power sales margin revenue should be added.

20
21 **Q. What is the total amount of your proposed Transmission Capacity adjustment**
22 **to the Company's proposed rate year power costs?**

1 A. I reduce overall proposed transmission expense by the full \$414,000 amount for the
2 23 MWs of BPA transmission contract cost.

3
4 **F. Cedar Hills Gas MTM**

5
6 **Q. Your next adjustment is labeled “Cedar Hills Gas MTM” in Exhibit No. __**
7 **(APB-2). Please provide the context of this adjustment.**

8 A. This adjustment removes the mark-to-market expense associated with a speculative
9 gas purchase. Beginning on page 32 of Exhibit No. __ (DEM-1CT), Mr. Mills
10 discusses a transaction related to the acquisition of emission credits associated with
11 gas produced by the Cedar Hills Regional landfill. As part of the agreement, King
12 County will receive a share of the net proceeds from the sale of the gas or the RECs
13 produced by Cedar Hills’ gas when used to generate electricity. The Company goes
14 on to state that it intends to monetize the renewable attributes of the gas, but has not
15 yet signed agreements for sale of the renewable attributes. As part of the Company’s
16 rate year power costs, PSE also proposes that ratepayers absorb the mark-to-market
17 costs associated with the Cedar Hills gas transaction. PSE included in its original
18 filing [REDACTED] million of mark-to-market costs tied to Cedar Hills. The mark-to-
19 market costs associated with Cedar Hills was then subsequently reduced in the
20 supplemental filing to [REDACTED] million due to slightly higher gas futures prices, as
21 shown in Exhibit No. __ (APB-7C).

22 Regarding the gas itself, PSE states that when the gas is sold, the Company
23 will account for it as a sale of excess gas by crediting FERC account 456 with the

1 sales price of the gas sold. This entire transaction appears to be for the sole purpose
2 of monetizing any renewable attributes and then asking ratepayers to not only bear
3 the speculative risk of purchasing and selling the gas commodity, but also to pay in
4 base rates the mark-to-market costs of the transaction.

5
6 **Q. Please describe your Cedar Hills Gas adjustment.**

7 A. At a minimum, ratepayers should not pay the mark-to-market costs related to the
8 Cedar Hills transaction. On its face, the transaction treats the gas commodity portion
9 as a speculative buy/sell arrangement in order to receive benefits from the renewable
10 side of the transaction and was not acquired under any least gas cost acquisition
11 strategy. Clearly, the gas was not acquired to meet generation needs based on the
12 Company's stated intent regarding the sale of the gas, and thus, should not be
13 included in the determination of net power costs.

14 For purposes of this proceeding and notwithstanding my concerns about
15 including any mark-to-market costs in base rates for companies with a PCA, I
16 remove the mark-to-market costs assigned to Cedar Hills from net power costs as a
17 way to mitigate the effect of the transaction on ratepayers. This effectively removes
18 the cost of hedging associated with these volumes of gas clearly not acquired for
19 generation requirements but, rather, maintained for resale.

20 The mark-to-market costs associated with Cedar Hill gas is not included in
21 my proposed mark-to-market adjustment discussed earlier in my testimony.

22 However, the Commission could also remove this expense from projected rate year

1 power costs based on increasing the excess hedged gas volumes over modeled
2 volumes due to the Cedar Hill transaction.

3
4 **Q. What is the total amount of your proposed Cedar Hills Gas adjustment to the**
5 **Company's proposed rate year power costs?**

6 A. My proposed adjustment reduces the "not in models" MTM expenses by \$1.612
7 million, as compared to the Company's supplemental filing. However, the
8 calculation of the actual MTM amount associated with Cedar Hills ultimately to be
9 removed will be greatly affected by any gas/electric market price updates that take
10 place. As gas prices decrease, the relative amount of this adjustment will also
11 increase. Any compliance filing by the Company should take this into consideration.

12
13 **G. Other Production O&M Expense**

14
15 **Q. Your next adjustment is labeled "Other Production O&M Expense" in Exhibit**
16 **No. __ (APB-2). Please provide the context of this adjustment.**

17 A. This adjustment results from a more appropriate rate year treatment of miscellaneous
18 production O&M expenses. A significant portion of the proposed [REDACTED] million
19 Production O&M rate year expense includes what the Company labeled "Other
20 Production O&M" in its workpapers. The amount proposed by the Company to
21 include in base rates is approximately [REDACTED] million and represents the test year
22 amount for those accounts included as Other Production O&M.

23

1 **Q. Please explain your issues with the Company's adjustment.**

2 A, The proposed [REDACTED] million is an issue for several reasons. First, the proposed amount
3 is significantly greater than what has been allowed in previous rate cases. Page 1 in
4 Exhibit No. ___ (APB-8C), an excerpt from Mr. Mill's workpapers, shows the
5 proposed rate year Production O&M amounts for each of the Company's resources,
6 as well as amounts that have been allowed in previous proceedings. I have already
7 addressed the variability in non-contract major maintenance for the gas fired
8 turbines. The category labeled "Other" shows significant variability, ranging from
9 just over [REDACTED] million for the 11/2008 to 10/2009 period to approximately [REDACTED]
10 million for the 2010 test year amount.

11 My second issue with the Company's proposal is its comparison to the
12 amount the Company has apparently budgeted during the rate year. Pages 2 through
13 4 of Exhibit No. ___ (APB-8C) are the Company's response to ICNU Data Request
14 5.10. In that response, PSE provides a summary explanation of the "Other"
15 production O&M amounts for the test year, as well as budgeted amounts for 2012
16 and 2013. The response shows that 2012 and 2013 amounts of \$3.6 million and \$3.9
17 million, respectively, are both projected to be much lower than the test year and
18 Company proposed amount of \$4.5 million.

19 Finally, the information provided by the Company on page 4 of Exhibit No.
20 ___ (APB-8C) related to proposed rate year amounts for "Other" production O&M
21 items, raises additional questions as to the appropriate expense level. For example,
22 the response indicates an approximate amount of \$0.77 million for what is described
23 as "discretionary benefits" for 2010 test year actuals. No such amounts are indicated

1 for the 2012 or 2013 budget and the discretionary nature of the expense leads one to
2 question their appropriateness as a pro-forma rate year expense.

3
4 **Q. What is the appropriate methodology for developing production O&M expense
5 levels for the rate year and inclusion in base rates?**

6 A. Flexibility is the most important factor in developing the appropriate level for pro-
7 forma projections for production O&M expenses. For example, O&M expenses
8 related to specific in-place resources with a substantial and regular operations history
9 can best be estimated by using an historical average, such as the commonly used
10 five-year average. However, even when using this technique, historical expense
11 levels require some level of analysis to insure that unusual and extraordinary
12 expenses do not bias the results. It is still appropriate to use averages derived from
13 historical values after adjustments have been made to address inappropriate, unusual
14 or extraordinary items.

15
16 **Q. What other approaches can be used to develop appropriate production O&M
17 rate year amounts?**

18 A. For other resources, alternative approaches may be appropriate, including the use of
19 budgeted production O&M amounts. This is true if there has been some systemic
20 change in the operations of a resource or if there is reasonable evidence of a certain
21 level of expenses actually forecast to occur. For example, in the current environment
22 in which PSE files regular general rate cases, it may be appropriate to use external
23 rate year budgets to determine O&M expense levels for certain resources (such as the

1 Colstrip 1-4 units). Even though variations from test year and historical average
2 levels are evident, the budgets may represent the most accurate forecasted O&M
3 levels for rate year use. This may also hold true for non-resource specific and
4 variable production O&M expenses, such as those identified in Exhibit
5 No. ___ (APB-8C).

6 However, the use of budgeted amounts may be appropriate in an environment
7 of regular rate case filings, such as the Commission has been experiencing recently.
8 Otherwise, historical averages with their appropriate adjustments should be used.
9 Test year O&M expense levels should only be used lacking additional information,
10 as they represent only a snapshot look at what normally are variable expense levels.

11

12 **Q. Please describe your Other Production O&M Expense adjustment.**

13 A. The use of test year "Other" production O&M levels for rate year projections is not
14 appropriate given the other alternatives. As shown in Exhibit No. ___ (APB-8C),
15 both historical expenses and future budgeted estimates are available. However, in
16 this case, the historical amounts include individual expenditures that may not meet
17 pro-forma standards, such as the item described as discretionary benefits. Given the
18 presence of what appears to be reasonable budgeted amounts and the trend of regular
19 rate case filings, I have adjusted the Company's filed production O&M using the
20 2012 budget amount shown in Exhibit No. ___ (APB-8C).

21

22 **Q. What is the total amount of your proposed Other Production O&M Expense**
23 **adjustment to the Company's proposed rate year power costs?**

1 A. The total rate year Production O&M expense level is reduced by \$912,700. This
2 reduces the adjustment of Other Production O&M Expense to \$3,590,116, as
3 compared to the Company's filed amount of \$4,502,816.
4

5 **H. Gas Price Update**

6
7 **Q. Your last adjustment is labeled "Gas Price Update" in Exhibit No. __ (APB-2).
8 Please explain the context of this adjustment.**

9 A. This adjustment estimates the effect of more recent 3-month rolling average gas
10 prices on rate year power costs than was available when the Company made its
11 supplemental filing in September. The Commission has recently allowed electric
12 utilities to update certain costs during the general rate case process, as long as there
13 is a suitable transparency to the calculation and adequate time for other parties to
14 review the updated amounts. Typically, those updates have been limited to
15 forecasted gas and electric market prices, new firm contracts, or budget updates from
16 third party owners of resources such as the Mid-Columbia project owners. This
17 transparency is critical, given the timing of when the updates are allowed to occur.

18 On September 1, 2011, the Company submitted supplemental testimony
19 addressing updated projected rate year power costs. Among the numerous updated
20 items was the AURORA model database for gas prices. For the update, PSE used a
21 three-month average of daily forward gas prices for the rate year as of July 26, 2011.
22 The Company states that the update utilized an average gas price of \$4.79/MMBTU,
23 which is \$0.07/MMBTU higher than the price used in the original filing. To reflect

1 the increase, rate year power costs were projected to be \$1.7 million higher, after
2 mark-to-market adjustments were included.

3

4 **Q. Has the Company further updated its projected rate year power costs?**

5 A. No.

6

7 **Q. How has three-month average of daily forward gas price forecasts for the rate
8 year behaved since the Company made its supplemental update filing?**

9 A. The three-month average of daily forward rate year gas price prices has declined
10 significantly. Based on a mid-November calculation, prices have fallen over 8.5
11 percent or an amount approximating \$0.41/MMBTU – a significant decline. Exhibit
12 No. ___ (APB-9C) is an excerpts from Mr. Mills' workpapers showing recent Sumas
13 gas price trends, with a Staff handwritten notation indicating the level of the more
14 recent mid-November, 3-month rolling average gas price forecast.

15

16 **Q. Have you estimated the effect on projected rate year power costs of the recent
17 rate year gas prices?**

18 A. Yes. For illustrative purposes only I calculated an estimated effect without re-
19 running the Company's AURORA production cost model. This gives only a rough
20 estimate of the effect of gas price changes. An updated AURORA model using the
21 latest available prices will re-dispatch resources based on the reduced gas prices and
22 electric market prices during the rate year to derive new normalized power costs. I
23 have simply used a ratio of power cost effect to gas price change to estimate a result.

1

2 **Q. What is the estimated amount of your proposed Gas Price Update adjustment**
3 **to the Company's proposed rate year power costs?**

4 A. Using the previously discussed \$1.7 million increase in projected rate year costs that
5 in turn used a \$0.07/MMBTU average gas price increase, I calculated an estimated
6 effect of approximately a \$9.96 million decrease in projected rate year power costs
7 resulting from an average rate year gas price decrease of \$0.41/MMBTU. It is
8 expected that the effect on rate year power costs will increase significantly as rate
9 year forward gas prices have continued to fall. In order to more accurately determine
10 the appropriate rate year costs, the Company should provide a complete update of
11 projected rate year power costs due to gas price forecast changes in its rebuttal filing.
12 A further update should be ordered as part of the compliance filing. For purposes of
13 Staff's recommended power costs adjustments I have used the estimate above.

14

15 **Q. Does this conclude your testimony?**

16 A. Yes.

17

18