

**EXH. PKW-15CT
DOCKETS UE-170033/UG-170034
2017 PSE GENERAL RATE CASE
WITNESS: PAUL K. WETHERBEE**

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

**Docket UE-170033
Docket UG-170034**

**PREFILED REBUTTAL TESTIMONY
(CONFIDENTIAL) OF
PAUL K. WETHERBEE
ON BEHALF OF PUGET SOUND ENERGY**

**REDACTED
VERSION**

AUGUST 9, 2017

PUGET SOUND ENERGY

**PREFILED REBUTTAL TESTIMONY (CONFIDENTIAL) OF
PAUL K. WETHERBEE**

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1 **PUGET SOUND ENERGY**

2 **PREFILED REBUTTAL TESTIMONY (CONFIDENTIAL) OF**
3 **PAUL K. WETHERBEE**

4 **I. INTRODUCTION**

5 **Q. Are you the same Paul K. Wetherbee who submitted prefiled direct**
6 **testimony on January 13, 2017, and prefiled supplemental direct testimony**
7 **on April 3, 2017, on behalf of Puget Sound Energy (“PSE”) in this**
8 **proceeding?**

9 A. Yes I am.

10 **Q. What is the purpose of your rebuttal testimony?**

11 A. My rebuttal testimony presents PSE’s response to issues raised in the prefiled
12 response testimonies of Commission Staff and the Industrial Customers of
13 Northwest Utilities (“ICNU”). Specifically, I address:

- 14 (i) PSE’s approach to estimating the impacts of the Clean Air
15 Rule on rate year power costs;
- 16 (ii) Treatment of costs and benefits of PSE’s participation in
17 the California Independent System Operator (“CAISO”)
18 Energy Imbalance Market;
- 19 (iii) Input assumptions for PSE’s gas fired resources, including
20 variable operating and maintenance expenses and major
21 maintenance costs;
- 22 (iv) The wind forecast used to estimate power costs;
- 23 (v) The historical data used to calculate day ahead wind
24 integration costs; and

1 (vi) The timing of recalculating power costs for a new baseline
2 rate to be implemented when a portion of Microsoft's load
3 becomes a retail wheeling load.

4 Finally, this rebuttal testimony provides an update to PSE's proposed power costs
5 for the rate year 2018.

6 **Q. What level of power costs does PSE propose in this rebuttal filing?**

7 A. Projected rate year power costs in this rebuttal filing are \$714.9 million. This is a
8 \$22.9 million (or 3.1 percent) reduction from the previously filed power costs of
9 \$737.7 million in the supplemental filing, and a \$0.8 million (0.1 percent)
10 increase from rates approved in the 2016 Power Cost Update and currently in
11 place.

12 II. CLEAN AIR RULE

13 **Q. How did PSE treat the Clean Air Rule in its projected power costs in this**
14 **proceeding?**

15 A. As described in my prefiled direct testimony,¹ PSE estimated emissions limits for
16 the resources that are likely to have limits given descriptions in the rule, which are
17 the combined cycle plants. PSE calculated the limits by plant based on
18 Washington State Department of Ecology ("Ecology") data from 2012 through
19 2015 and descriptions in the rule of how Ecology will calculate emissions limits
20 for stationary sources. PSE used data through 2015 because 2016 data were not
21 complete at the time PSE prepared its initial filing. PSE placed these emissions

¹ See generally Wetherbee, Exh. PKW-1CT at 47:4 – 49:8.

1 limits in its AURORA model. The limits resulted in reduced output from the
2 combined cycle resources than would have been indicated absent the caps. PSE
3 also made some downstream adjustments to Not in Aurora costs.

4 **Q. How do other parties respond to PSE's treatment of the Clean Air Rule?**

5 A. Commission Staff and ICNU oppose inclusion of any costs related to the Clean
6 Air Rule. No other party commented on PSE's treatment of the Clean Air Rule.
7 Commission Staff argues that (i) PSE's baseline emission limits are not known;²
8 (ii) PSE's analysis results in over-compliance with the Clean Air Rule;³ (iii) the
9 restriction of individual resources rather than the aggregate resources
10 misrepresents the Clean Air Rule;⁴ (iv) PSE should not make assumptions about
11 the emissions limits of other parties;⁵ and (v) there are other ways to comply with
12 the rule, including offsetting emissions by purchase of emissions reduction units
13 ("ERUs") as described in the rule.⁶

14 **Q. Are PSE's baseline emission limits known and measurable?**

15 A. Yes. The methodology that will be used by Ecology to calculate the emissions
16 baseline is specified in WAC 173-442-050(3)(a), which directs Ecology to
17 calculate the five-year period average of emissions data between 2012 through
18 2016:

2 Frankiewich, Exh. KAF-1T at 22:1 – 24:10.

3 Frankiewich, Exh. KAF-1T at 25:3-12.

4 Frankiewich, Exh. KAF-1T at 25:16 – 26:16.

5 Frankiewich, Exh. KAF-1T at 27:3-14.

6 Frankiewich, Exh. KAF-1T at 27:18 – 30:3.

1 (a) Ecology must calculate the Category 1 baseline GHG
2 emissions value based on the average (in MT CO₂e per year)
3 of:

4 (i) Five years of covered GHG emissions data between
5 2012 through 2016; or

6 (ii) At least three years of covered GHG emissions subject
7 to (b) of this subsection.⁷

8 Using this guideline, PSE was able to calculate its baseline emissions values.

9 Commission Staff's testimony refers to WAC 173-442-050(3) as evidence that

10 Ecology has discretion to exclude up to two years of data to calculate baselines.

11 However, WAC 173-442-050(3)(b) provides Ecology the discretion to exclude a

12 year of data only under two circumstances—(i) if a facility was in a period of

13 curtailment during a calendar year, or (ii) if the methodology to calculate

14 emissions by the facility changes and the variance between old and new is greater

15 than fifteen percent without any change to general operating conditions:

16 (b) Ecology may omit a specific calendar year from calculating
17 the baseline GHG emissions value when the data meets at
18 least one of the following criteria:

19 (i) The data represents a significant difference from the
20 average data based on all of the following:

21 (A) Primarily caused by a change in the GHG
22 emissions calculation methodology approved
23 under chapter 173-441 WAC during the baseline
24 period that is not correctable by adjusting the
25 existing reported GHG data;

26 (B) The GHG emissions calculation methodology
27 produced a fifteen percent or more difference
28 between that calendar year's GHG emissions and

⁷ WAC 173-442-050(3)(a).

1 the 2012 through 2016 average of GHG emissions
2 using the methodology in (a) of this subsection;
3 and

4 (C) The change is not the result of a process or
5 production change regardless of how large,
6 unusual, or outside of the control of the covered
7 party; or

8 (ii) The calendar year contains a period of curtailment.⁸

9 Other than routine outages for regular maintenance, PSE did not curtail plant
10 operations during the 2012 through 2016 period, and the methodology for
11 calculating emissions did not change. Therefore, it is reasonable to assume that
12 PSE's baselines will be based on all five years of historical data.

13 Commission Staff also argues that the caps PSE used in its analysis are not
14 sufficient because they were based on only four years of data (i.e., 2012 through
15 2015). PSE filed its initial filing in this proceeding on January 13, 2017. At the
16 time PSE prepared its analysis for the initial filing in this proceeding, calendar
17 year 2016 had not concluded, and the full year of data for 2016 were not
18 available. Now, PSE has 2016 data, and PSE has recalculated its baseline
19 emissions limits and 2018 caps using a full five years of data (i.e., 2012 through
20 2016). Please see the First Exhibit to the Prefiled Rebuttal Testimony of Paul K.
21 Wetherbee, Exh. PKW-16, for the data for the full five years (i.e., 2012 through
22 2016). The updated estimate of PSE's aggregate 2018 cap is 1.6 percent below the
23 level assumed in the initial filing in this proceeding.

⁸ WAC 173-442-050(3)(b).

1 **Q. Please address Commission Staff's examples of variance in reasonable**
2 **estimates of Clean Air Rule baselines.**

3 A. Commission Staff's calculation of Clean Air Rule baseline estimates on
4 Exhibit KAF-8 contains two mathematical errors. In calculating the Goldendale
5 Generating Station modified baseline, Commission Staff excluded actual data for
6 calendar year 2016 in calculating the 2012 through 2016 average with +/-15%
7 outliers removed and, instead, mistakenly used the 2012 through 2015 average.
8 The same miscalculation also exists for the 2012 through 2016 average with +/-
9 20% outliers removed.

10 As shown in Table 1 below, correction of these errors result in a one percentage
11 point reduction to Commission Staff's estimates of variance from PSE's
12 emissions baseline calculation in the scenarios with +/-15% and +/-20% outliers
13 removed.

**Table 1. Correction to Staff Illustration of Variance in
Clean Air Rule Baseline**

	2012-2015 Average PSE Initial Filing*	2012-2016 Average No Outliers Removed	2012-2016 Average +-15% Outliers Removed	2012-2016 Average +-20% Outliers Removed
Total PSE Plant Emissions (metric tons CO ₂ e) – Staff Calculations	1,779,572	1,750,427	1,833,704	1,834,250
Percentage Difference from PSE’s Emissions Baseline Calculation – Staff Calculations	100.0%	98.4%	103.0%	101.7%
Total PSE Plant Emissions (Metric Tons CO ₂ e) – Corrected	1,779,572	1,750,427	1,811,306	1,788,333
Percentage Difference from PSE’s Emissions Baseline Calculation – Corrected	100.0%	98.4%	101.8%	100.5%

* Levels are estimates of 2017 baseline using 2012-2015 data from the Fourth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-5.

1 Commission Staff asserts that “baseline estimates might vary by as much as
2 5 percent,”⁹ but the highest variance presented in Commission Staff’s table is
3 3.6 percent.¹⁰ As previously stated, the applicable rule requires Ecology to use
4 five years of data except under two circumstances, neither of which applies to
5 PSE’s resources. Therefore, Commission Staff’s assertion that baseline estimates
6 could vary significantly from PSE’s estimates is speculative.

⁹ Frankiewicz, Exh. KAF-1T at 24:4-5.

¹⁰ Frankiewicz, Exh. KAF-1T at 24:Table 2.

1 **Q. Did PSE continue to include costs associated with Clean Air Rule compliance**
2 **in its projected power costs in this rebuttal filing?**

3 A. Yes. PSE continues to include costs associated with Clean Air Rule compliance in
4 its projected power costs in this rebuttal filing. However, in response to concerns
5 raised by Commission Staff and ICNU, PSE has changed its approach.

6 **Q. How did PSE treat the Clean Air Rule in its projected power costs in this**
7 **rebuttal filing?**

8 A. Instead of modeling Clean Air Rule caps on combined cycle units within
9 AURORA, PSE ran AURORA without Clean Air Rule constraints. PSE then
10 compared the aggregate emissions from the combined cycle plants from the
11 AURORA output with the estimated collective cap under the Clean Air Rule. The
12 amount by which the aggregate emissions from the combined cycle plants from
13 the AURORA output exceeded the anticipated collective cap under the Clean Air
14 Rule represents excess emissions and noncompliance with the Clean Air Rule. For
15 the rebuttal filing, this is an exceedance of [REDACTED] percent or [REDACTED] metric tons
16 CO₂e above the 2018 cap. PSE then estimated the cost of compliance by
17 multiplying the excess emissions by an assumed price of an ERU.

18 **Q. What ERU price did PSE assume?**

19 A. Renewable energy credits (“RECs”) can be converted to ERUs pursuant to
20 WAC 173-442-160(5)(b). PSE estimated a price for 2018-19 RECs eligible to be
21 used for compliance with Washington’s renewable portfolio standard (“RPS”)

1 based on market prices. This REC price is \$ [REDACTED] /REC with a conversion of
2 2.25 RECS per ERU consistent with WAC 173-442-160(5)(c)(i)(C).

3 **Q. Can these RPS-eligible RECs be converted to ERUs?**

4 A. Some of them can, and some cannot. The rule allows for conversion of RECs
5 generated by resources located in Washington to ERUs. WAC 173-442-
6 160(5)(b)(i) provides that “[o]nly those eligible renewable resources physically
7 located in Washington may generate ERUs.”¹¹ However, not all RPS-eligible
8 RECs are generated in Washington. One of the challenges with Clean Air Rule
9 compliance is that there is not an established market for ERUs. ERUs and
10 Washington RECs are not defined products in the marketplace. The price PSE
11 used to estimate the costs of Clean Air Rule compliance is a proxy for
12 Washington RECs based on limited market information.

13 **Q. Could ERU prices increase?**

14 A. Yes. ERU prices could increase. Demand for ERUs could increase dramatically as
15 regulated entities take action to comply with the Clean Air Rule. This demand
16 would come from entities regulated by the Clean Air Rule, including natural gas
17 local distribution companies, power plants, petroleum product producers and
18 other stationary sources.

¹¹ WAC 173-442-160(5)(b)(i).

1 **Q. How does the ERU price PSE used compare to information on ERU prices**
2 **provided by Ecology?**

3 A. In its Final Cost-Benefit and Least-Burdensome Alternative Analysis¹², Ecology
4 presented a range of ERU costs of \$3 to \$57 per metric ton (“MT”) of CO₂e, with
5 one MT being equivalent to one ERU, based on the alternative options for
6 compliance with the rule. The \$[REDACTED]/REC translates to \$[REDACTED]/MT CO₂e based
7 on Ecology’s conversion factor of 2.25 RECs per ERU. The price assumed by
8 PSE is in the bottom quartile of Ecology’s range. The wide range of estimates
9 provided by Ecology is evidence of the price risk associated with ERUs discussed
10 above and indicates that PSE’s price assumption is moderate.

11 **Q. What is the cost of Clean Air Rule compliance based on this analysis?**

12 A. This analysis results in an updated estimate of Clean Air Rule compliance costs of
13 \$5.38 million for the rate year, which is an adjustment outside of AURORA.
14 Please see the Second Exhibit to the Prefiled Rebuttal Testimony of Paul K.
15 Wetherbee, Exh. PKW-17C, for the calculation of the Clean Air Rule compliance
16 cost estimate. This is a reduction of \$15.8 million from the approach PSE used in
17 its supplemental filing, updated to be consistent with the input assumptions in the
18 rebuttal power costs.

¹² Final Cost-Benefit and Least-Burdensome Alternative Analysis, September 2016, Publication no. 16-02-015, pages 16-18.

1 **Q. Why did PSE change its modeling approach to the Clean Air Rule?**

2 A. The approach PSE used in its initial filing, to place emissions limits on affected
3 resources, was a straightforward approach based on the most known aspect of the
4 rule, the emissions limits. Commission Staff and ICNU witnesses objected to this
5 approach, and the rule does provide for alternative ways to comply, so PSE
6 addressed their concerns by estimating compliance costs based on purchase of
7 RECs instead of limiting plant output.

8 The difficulty modeling the costs of Clean Air Rule compliance highlights the
9 risks associated with the rule. PSE is required to comply with the rule, but there is
10 a limited supply of convertible RECs, no liquid market for ERUs, and potential
11 for price volatility in convertible RECs and ERUs as covered parties work to
12 comply with the rule.

13 **Q. Has PSE addressed the concerns raised by Commission Staff and ICNU**
14 **regarding PSE's estimated compliance costs with regard to the Clean Air**
15 **Rule?**

16 A. Yes. One objection was that PSE's initial approach resulted in over-compliance
17 with the Clean Air Rule. For example, the emissions levels in PSE's supplemental
18 filing were [REDACTED] metric tons of CO₂e below PSE's collective cap due to
19 modeling limitations. The updated approach to Clean Air Rule compliance
20 presented in this rebuttal testimony calculates the minimum number of RECs
21 necessary to comply with the projected Clean Air Rule requirements.

1 Another objection was that PSE assumed Clean Air Rule emissions limits of other
2 plants in Washington not owned or operated by PSE. Those assumptions were
3 reasonable and necessary using the approach in the initial filing. However, now
4 that compliance costs are calculated outside of AURORA, there is no need to
5 place emissions limits on other Washington plants to generate accurate dispatch
6 data. In other words, assumptions about caps for other plants are not necessary
7 given this updated approach.

8 The remaining objection was that there are ways to comply with the Clean Air
9 Rule without curtailing emissions, such as by acquiring ERUs. PSE's updated
10 approach addresses this concern by estimating compliance costs using known and
11 measurable emissions caps to estimate REC purchases for compliance.

12 **Q. What other comments does PSE have with respect to the Clean Air Rule?**

13 A. The Clean Air Rule is an existing rule with which PSE must comply. Costs
14 associated with compliance with the Clean Air Rule include market purchases to
15 offset limits on gas-fired generation or ERU purchases. The Commission should
16 include the recovery of these compliance costs in rates. PSE's updated approach
17 presented in this rebuttal testimony represents a reasonable methodology to
18 estimate these compliance costs for the rate year that considered and responded to
19 the issues raised by both Commission Staff and ICNU. If, however, the
20 Commission declines to allow recovery of these costs in rates based on this
21 rebuttal testimony, PSE would propose that the Commission authorize PSE to
22 defer Clean Air Rule compliance costs for future recovery.

1 **III. ENERGY IMBALANCE MARKET**

2 **Q. How did PSE treat projected costs and benefits related to participation in the**
3 **CAISO Energy Imbalance Market in the initial filing?**

4 A. PSE included \$8.47 million of assumed benefits related to participation in the
5 CAISO Energy Imbalance Market. This amount exactly offsets the sum of rate
6 year power costs (\$2.33 million) and rate base related costs (\$6.1 million)
7 discussed in the Prefiled Direct Testimony of Katherine J. Barnard, Exh. KJB-1T.
8 Projecting rate year benefits that offset rate year costs had the effect of protecting
9 customers from paying any costs associated with the CAISO Energy Imbalance
10 Market during the rate year.

11 **Q. Did any party express concerns with respect to PSE’s treatment of costs and**
12 **benefits associated with the CAISO Energy Imbalance Market?**

13 A. Commission Staff was the sole party to express concern with PSE’s treatment of
14 costs associated with the CAISO Energy Imbalance Market. Commission Staff
15 argues instead that costs associated with the CAISO Energy Imbalance Market
16 should not be included in either general rates or the baseline rate.¹³ Commission
17 Staff proposes to include such costs associated with the CAISO Energy Imbalance
18 Market as a line item in the Power Cost Adjustment (“PCA”) and benefits would
19 be reflected in the PCA sharing bands.¹⁴

¹³ Frankiewicz, Exh. KAF-1T at 7:12 – 13:11.

¹⁴ Frankiewicz, Exh. KAF-1T at 13:15 – 17:9.

1 **Q. Describe PSE's understanding of Commission Staff's alternative proposal.**

2 A. PSE's understanding is that Commission Staff's alternative proposal would
3 include costs associated with the CAISO Energy Imbalance Market as allowable
4 costs when determining actual costs in each monthly calculation of the PCA
5 imbalance. These costs would result in PCA under-recoveries because these costs
6 are not reflected in the baseline rate. The PCA under-recoveries would be offset,
7 in whole or in part, by benefits associated with the CAISO Energy Imbalance
8 Market, which would flow through the PCA as over-recoveries because they
9 would also not be included in the baseline rate.

10 **Q. Does PSE support this treatment of EIM costs and benefits?**

11 A. No. Commission Staff's proposal violates the settlement agreement among
12 Commission Staff, PSE, and Public Counsel that was approved by the
13 Commission in Docket UE-130617. In that docket, PSE and stakeholders
14 participated in a collaborative process after the 2013 PCORC to re-evaluate the
15 PCA mechanism. A primary outcome of that collaborative was a settlement in
16 which the settling parties agreed to remove fixed production costs from the PCA.
17 The settlement also included a five-year moratorium on changes to the PCA. The
18 changes to the PCA resulting from the settlement were just implemented in
19 January 2017. Commission Staff's proposal would violate the settlement by
20 including fixed costs associated with the CAISO Energy Imbalance Market in the
21 PCA and by proposing changes to the PCA mechanism during the moratorium.

1 **Q. Does the *PacifiCorp* case discussed by Commission Staff support the position**
2 **that fixed costs related to the CAISO Energy Imbalance Market should be**
3 **included in the PCA?**

4 A. No. PSE's proposal is positioned differently from the PacifiCorp proposal in
5 Docket UE-152253 cited by Commission Staff. In that case, PacifiCorp filed an
6 expedited rate filing, which the Commission converted to a general rate case. The
7 filing did not include power costs whatsoever. Because there was no opportunity
8 to include the benefits of the CAISO Energy Imbalance Market in power costs in
9 Docket UE-152253, the Commission allowed PacifiCorp to include the fixed
10 costs related to the CAISO Energy Imbalance Market in actual power costs in the
11 annual PCA mechanism filing. The Commission noted, however, that such an
12 approach was only permitted because PacifiCorp had not filed for a change in
13 power costs:

14 In this proceeding, Pacific Power chose not to file for a change in
15 power costs and therefore precluded a change to the baseline
16 power cost in the PCAM. Without a means for matching benefits
17 with the burden of the EIM costs, recovery of EIM costs in non-
18 power cost rates is limited.

19 In approving Pacific Power's proposal, we are allowing Pacific
20 Power to include fixed costs related to the EIM in the actual power
21 costs in its annual PCAM filing, but we do not approve their
22 inclusion indefinitely. Pacific Power, in its next general rate case,
23 must remove the EIM fixed costs from the PCAM's annual true-up
24 and propose their recovery in non-power cost rates. The
25 Commission will determine at that time if the costs are
26 commensurate with the benefits.¹⁵

¹⁵ *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Docket UE-152253, Order 12 at ¶¶ 223-24 (Sept. 1, 2016).

1 In contrast, PSE's filing in this proceeding includes power costs. PSE has
2 proposed to include (i) the fixed costs related to the CAISO Energy Imbalance
3 Market in non-power cost rates and (ii) the power costs related to the CAISO
4 Energy Imbalance Market in the PCA. PSE has also proposed to include benefits
5 of \$8.47 million to offset the fixed rate base costs and the power costs related to
6 the CAISO Energy Imbalance Market. Indeed, PSE's proposal is consistent with
7 the Commission's direction in the *PacifiCorp* case discussed by Commission
8 Staff.

9 **Q. Will PSE get cost recovery of Energy Imbalance Market related costs given**
10 **Staff's proposal as Staff asserts?¹⁶**

11 A. Inclusion of Energy Imbalance Market costs in the PCA as proposed by Staff does
12 not provide for cost recovery. As indicated by the Commission in Order 08 in
13 PSE's 2011 general rate case, the PCA is not a cost recovery mechanism:

14 We note above in our discussion of hedging costs that the PCA
15 mechanism is not a cost recovery mechanism. We strive to
16 determine net power costs for the rate year as close as can be
17 reasonably forecast to what will be the Company's actual cost
18 during that period. Excluding costs we know PSE will incur, such
19 as wind integration cost would frustrate that goal. The PCA
20 depends on our establishing accurate baseline power costs that
21 include all reasonably anticipated, prudently incurred costs. The
22 purpose of the PCA is to capture significant (i.e., greater than net
23 \$20 million plus or minus during any given PCA period)
24 unanticipated deviations from that baseline. Its purpose manifestly

¹⁶ Frankiewich, Exh. KAF-1T at 14:1-3.

1 is not to capture known costs intentionally left out of the baseline
2 power cost determination.¹⁷

3 **Q. What costs and benefits related to the CAISO Energy Imbalance Market did**
4 **PSE include in power costs in this rebuttal testimony?**

5 A. PSE's power costs in this rebuttal filing continue to include \$8.47 million of
6 benefits and \$2.33 million of costs.

7 **Q. How does the \$8.47 million of projected benefits compare with benefits that**
8 **PSE has actually achieved since joining the CAISO Energy Imbalance**
9 **Market?**

10 A. CAISO produces quarterly reports of estimated benefits for Energy Imbalance
11 Market participants. In these reports CAISO estimated PSE benefits to be
12 \$5.43 million in the first nine months PSE participated in the market.

13 **IV. INPUT ASSUMPTIONS FOR GAS FIRED RESOURCES**

14 **Q. What variable operations and maintenance (“O&M”) and major**
15 **maintenance costs did PSE use in its AURORA analysis for estimating**
16 **proposed power costs?**

17 A. As indicated in my prefiled direct testimony,¹⁸ PSE used O&M costs established
18 by CAISO to model the dispatch of all gas-fired resources in AURORA except
19 for the Encogen Generating Station (“Encogen”). For Encogen, PSE used a

¹⁷ *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 & UG-111049, Order 08 at ¶ 251 (May 7, 2012).

¹⁸ Wetherbee, Exh. PKW-1CT at 62:5-8.

1 calculated cost based on three years of historical data. PSE also used estimated
2 major maintenance costs as hurdles to unit commitment and dispatch in the
3 AURORA analysis. The major maintenance costs were developed based on PSE
4 data and negotiations with CAISO. Both the CAISO variable O&M and major
5 maintenance costs are also used for PSE's daily operational unit commitment and
6 dispatch decisions. Table 16 of my prefiled direct testimony also presents PSE
7 calculated variable O&M based on three years of historical data, for comparison
8 purposes.¹⁹

9 **Q. Are the variable O&M and major maintenance costs included in power costs**
10 **in this proceeding?**

11 A. No. As explained in my prefiled direct testimony,²⁰ O&M costs are not part of
12 power costs. They are relevant to the unit commitment and dispatch decisions
13 because those decisions are based on the relative costs of purchasing power versus
14 generating power, and O&M costs are part of that economic decision.

15 **Q. What inputs does Commission Staff challenge with respect to gas-fired**
16 **resources?**

17 A. Commission Staff objects to PSE's use of CAISO variable O&M and the
18 inclusion of major maintenance costs in its unit commitment and dispatch logic to
19 project power costs in this proceeding.²¹ Commission Staff also criticizes the PSE

¹⁹ Wetherbee, Exh. PKW-1CT at 63:Table 16.

²⁰ Wetherbee, Exh. PKW-1CT at 63:3 – 64:2.

²¹ Gomez, Exh. DCG-1CT at 18:1-15.

1 calculated variable O&M presented in Table 16 of my prefiled direct testimony on
2 the grounds that it relied on plant costs and generation data from 2013-2015 that
3 predates the test year.²²

4 **Q. Do other stakeholders challenge the input assumptions PSE used in its**
5 **analysis?**

6 A. No. No other stakeholder challenges the input assumptions that PSE used in its
7 analysis.

8 **Q. What is Commission Staff's proposal with respect to variable O&M?**

9 A. Commission Staff proposes use of (i) variable O&M based on test year actual
10 costs and (ii) no major maintenance costs to model unit commitment and dispatch
11 decisions.²³

12 **Q. Does PSE support the use of test year variable O&M as proposed by**
13 **Commission Staff?**

14 A. No. PSE does not support the use of test year variable O&M as proposed by
15 Commission Staff.

16 Variable O&M costs come in chunks. While these costs depend on generation,
17 they do not correspond directly to the level of energy production in a given twelve
18 month period. A plant might require parts for a corrective maintenance event one
19 year, and have much lower maintenance costs the next year. Energy also varies

²² Gomez, Exh. DCG-1CT at 18:15-18.

²³ Gomez, Exh. DCG-1CT at 19:8-10.

1 from year to year. When costs are divided by energy, the resulting cost per
2 megawatt-hour (MWh) can be much different in one year compared to the next.
3 Normalized variable O&M costs are a better input to the unit commitment and
4 dispatch logic, and are more consistent with PSE operations and with treatment of
5 production O&M costs in rates than test year variable O&M.

6 **Q. Are there other examples of costs being normalized for ratemaking**
7 **purposes?**

8 A. Yes. As stated in Commission Staff's testimony, the treatment of production
9 O&M costs is largely uncontroversial.²⁴ Since the Commission's order in the
10 2013 PCORC, PSE has deferred and amortized major maintenance costs for the
11 gas-fired resources.

12 If major maintenance costs were not normalized, the naturally-occurring peaks
13 and valleys in costs would be passed to customers from one rate period to the
14 next, creating inconsistency in rates over time. The amortization of these costs has
15 the effect of smoothing out costs over time to avoid big swings in costs passed on
16 to customers. This is relevant here because the same concern that costs vary from
17 one year to the next and one year's data may be abnormal is pertinent to the
18 variable O&M and major maintenance costs used as inputs to the power costs
19 model.

²⁴ Gomez, Exh. DCG-1CT at 18:5-10.

1 **Q. Does PSE continue to advocate use of CAISO variable O&M when**
2 **projecting power costs?**

3 A. Yes. CAISO variable O&M is consistent with (i) a market in which PSE operates
4 and (ii) the unit commitment and dispatch decisions PSE makes in daily
5 operations. Table 16 of my prefiled direct testimony presents the CAISO costs in
6 comparison with those calculated based on three years of PSE data. The CAISO
7 costs are a reasonable approximation of costs for use in unit commitment and
8 dispatch decisions.

9 **Q. Are there other alternatives to using either CAISO variable O&M or the test**
10 **year variable O&M?**

11 A. Yes. A three-year average of actual variable O&M costs calculated based on
12 historical plant data could serve as a suitable alternative. PSE has presented these
13 costs in Table 16 of my prefiled direct testimony.²⁵ A three-year average would
14 smooth out the peaks and valleys in costs.

15 **Q. What variable O&M did PSE use in its unit commitment and dispatch logic**
16 **in calculating power costs for this rebuttal filing?**

17 A. In calculating power costs for this rebuttal filing, PSE used the three-year average
18 variable O&M based on data from PSE's resources, with two small modifications.
19 First, net generation for Encogen was unavailable for all months when PSE
20 originally made the calculations. As mentioned in Commission Staff's

²⁵ Wetherbee, Exh. PKW-1CT at 63:Table 16.

1 testimony,²⁶ PSE substituted Encogen gross generation data for months missing
2 Encogen net generation data. PSE has since recalculated variable O&M for
3 Encogen using net generation for all months. This update results in an increase
4 from \$ [REDACTED]/MWh to \$ [REDACTED]/MWh.

5 PSE's analysis does not include variable O&M for Ferndale Generating Station
6 ("Ferndale"). In the initial filing in this proceeding, PSE used the CAISO variable
7 O&M cost in its analysis. To estimate power costs in this rebuttal filing, PSE used
8 the variable O&M cost for Sumas Generating Station ("Sumas") as a proxy for
9 Ferndale.

10 The change from using CAISO variable O&M to PSE's three-year average O&M
11 resulted in a reduction in power costs of approximately \$133,000.

12 **Q. Why did PSE's analysis not use actual variable O&M for Ferndale?**

13 A. PSE relies on a contractor to manage Ferndale, and detailed O&M costs are not
14 available to PSE. Sumas has similar technology and is therefore a reasonable
15 proxy for Ferndale.

16 **Q. What is the major maintenance adder and why did PSE use it in the dispatch
17 logic for projecting power costs in this proceeding?**

18 A. The major maintenance adder is an estimate of PSE's major maintenance costs,
19 modeled in AURORA on a dollars/start basis for simple cycle resources and a
20 dollars/MWh basis for combined cycle resources, as stated in my prefiled direct

²⁶ Gomez, Exh. DCG-1CT at 17, n.35.

1 testimony. These are different from the corrective maintenance costs included in
2 variable O&M. PSE included them in its unit commitment and dispatch logic in
3 projecting power costs because these costs are incurred based on the amount of
4 run time and the number of starts for a resource. Operationally, PSE uses these
5 costs in the economic unit commitment and dispatch decisions. PSE participates
6 in the CAISO market, and it is standard in the industry to include these costs in
7 economic decisions.

8 **Q. What are Commission Staff’s objections to using major maintenance costs in**
9 **the dispatch logic when projecting power costs in this proceeding?**

10 A. Commission Staff asserts that (i) inclusion of major maintenance in the dispatch
11 logic is double-counting of costs because there is an out-of-model adjustment for
12 these costs, (ii) PSE did not provide evidence that use of major maintenance costs
13 better characterizes unit commitment and dispatch of its gas-fired resources, and
14 (iii) use of major maintenance costs for modeling contradicts Commission input
15 provided in the 2015 Integrated Resource Plan (“2015 IRP”).²⁷

16 **Q. Are major maintenance costs accounted for in an out-of-model adjustment as**
17 **asserted by Commission Staff?**

18 A. No. The power costs adjustment related to major maintenance costs in “Costs not
19 in Aurora” is to remove non-fuel startup costs of the simple cycle gas-fired
20 resources. As discussed in my prefiled direct testimony, AURORA considers

²⁷ Gomez, Exh. DCG-1CT at 22:3 – 23:3.

1 startup costs in the unit commitment decision and includes these costs in fuel cost
2 of simple cycle combustion turbines. The adjustment is necessary to remove these
3 costs because they are variable O&M rather than power costs. For the rebuttal
4 filing, this is a decrease of \$ [REDACTED] to AURORA-generated power costs. The
5 purpose of this adjustment is to prevent double-counting of major maintenance
6 related startup costs for simple cycle gas-fired resources.

7 **Q. What does the Commission Staff say about the 2015 IRP?**

8 A. Commission Staff's testimony quotes a section of the Commission's
9 acknowledgement letter of the 2015 IRP,²⁸ in which the Commission stated that
10 zero energy output from peaking resources over a 20-year planning horizon was
11 unreasonable. This result was attributed to inclusion of major maintenance costs
12 in variable O&M.²⁹

13 **Q. Does the analysis in this proceeding include output from the peaking
14 resources?**

15 A. Yes, all of PSE's peakers produce energy for the rate year.

²⁸ Puget Sound Energy's 2015 Electric and Natural Gas Integrated Resource Plan, Dockets UG-141169 & UE-141170, Utilities and Transportation Commission Comments on Puget Sound Energy's 2015 Integrated Resource Plan at 8-9 (May 9, 2016).

²⁹ Gomez, Exh. DCG-1CT at 22:20 – 23:3.

1 **Q. Are there other differences between the major maintenance costs of peakers**
2 **in the 2015 IRP and those used to project power costs in this proceeding?**

3 A. Yes. In this proceeding the major maintenance costs of peakers are modeled on a
4 dollars per start basis. In the 2015 IRP they were modeled on a dollars per MWh
5 basis similar to other variable O&M.

6 **Q. Does the Commission's acknowledgement letter address treatment of major**
7 **maintenance costs for combined cycle resources?**

8 A. No. The Commission's discussion of major maintenance as a variable cost was
9 limited to the impact this assumption had on the economic unit commitment and
10 dispatch of peaking resources. The Commission's concern expressed in the letter
11 was not related to combined cycle plants.

12 **Q. Does the Commission's acknowledgement letter restrict use of major**
13 **maintenance costs in the unit commitment and dispatch decisions of simple**
14 **cycle and combined cycle resources?**

15 A. No. The Commission's criticism was that the result (i.e., zero output from peaking
16 plants) was not reasonable. The Commission did not suggest that major
17 maintenance costs should never be included as startup or variable O&M costs
18 when modeling unit commitment and dispatch.

1 **Q. Does PSE support the removal of major maintenance costs from the dispatch**
2 **logic as proposed by Commission Staff?**

3 A. No. PSE does not support the removal of major maintenance costs from the
4 dispatch logic as proposed by Commission Staff.

5 **Q. Why is it important to include major maintenance costs in the operational**
6 **unit commitment and dispatch decisions?**

7 A. It is important to include major maintenance costs in the operational unit
8 commitment and dispatch decisions because these costs are affected by run time
9 and the number of starts of a resource. Frequent commitment of thermal units will
10 result in compressing the intervals between major maintenance events. PSE
11 recovers major maintenance costs through the major maintenance amortization
12 component of the production O&M expense. Inclusion of major maintenance
13 costs in the commitment and dispatch decision process is intended to prevent
14 running the units in those instances where the increase in major maintenance
15 expense due to compression of the major maintenance schedule would more than
16 offset the benefit of reductions to power cost.

17 If PSE were to ignore these costs when deciding whether to commit a resource,
18 the decision would be biased toward running resources even in periods in which it
19 would be more economic to purchase power. This could result in higher power
20 costs, increased wear and tear on resources and higher maintenance costs over
21 time.

1 **Q. Did PSE include the major maintenance hurdle in its unit commitment and**
2 **dispatch logic when calculating power costs for this rebuttal filing?**

3 A. Yes. PSE included the major maintenance hurdle in its dispatch logic when
4 calculating power costs for this rebuttal filing.

5 **Q. Do you agree with Commission Staff's assertion that use of test year variable**
6 **O&M and removal of the major maintenance hurdle in the dispatch logic in**
7 **calculating power costs would reduce power costs by \$6.1 million?**³⁰

8 A. No. Commission Staff's assertion that use of test year variable O&M and removal
9 of the major maintenance hurdle in the dispatch logic in calculating power costs
10 would reduce power costs by \$6.1 million is inaccurate. Commission Staff bases
11 this calculation on a response to a data request in which PSE provided power cost
12 estimates using only variable operating—and not variable O&M—costs.
13 Additionally, a change in the dispatch hurdle would also affect the costs of
14 compliance with the Clean Air Rule, and the estimate provided by Commission
15 Staff fails to account for these compliance costs.

³⁰ See Gomez, Exh. DCG-1CT, at page 24, lines 3-7.

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V. WIND FORECAST

A. PSE Uses 2016 Forecasts

Q. What wind forecast did PSE use to develop its power costs projections in its initial filing in this proceeding?

A. PSE used 2016 wind forecasts developed by Vaisala Corporation (“Vaisala”), an outside expert on wind generation, for the wind resources owned by PSE (i.e., the Hopkins Ridge Wind Facility (“Hopkins Ridge”), the Wild Horse Wind Facility (“Wild Horse”), the Wild Horse Wind Facility Expansion (“Wild Horse Expansion”), and the Lower Snake River Wind Facility (“LSR”).

For the Klondike III power purchase agreement, PSE used the 2016 wind forecast provided by Avangrid Renewables, LLC, the owner of the Klondike III Wind Power Project (“Klondike III”).

Q. What wind forecasts has PSE used over time in general rate cases and power cost only rate cases?

A. When each wind resource was placed in service, PSE used preconstruction forecasts because there was no historical generation to inform a forecast. In the 2011 general rate case, PSE used updated wind forecasts developed in 2010 by DNV Global Energy Concepts, Inc. (“DNV”) for Hopkins Ridge and Wild Horse. These wind forecasts were incorporated in the rate approved in each of Docket UE-111048 & UG-111049 (the “2011 GRC”), Docket UE-130617 (the “2013 PCORC”), Docket UE-141141 (the “2014 PCORC”), and Docket UE-161135 (the “2016 Power Costs Update”).

1 **Q. Why did PSE update its wind forecasts and use them in this proceeding?**

2 A. PSE analyzed actual generation data for all years the resources have been in place
3 relative to the 2010 DNV forecasts. This analysis indicated that actual generation
4 was consistently below forecasted generation for all wind resources, including
5 Klondike III. The preconstruction and 2010 DNV forecasts did not reflect the
6 historical data currently available or current forecasting methodologies. PSE
7 (i) retained Vaisala to develop the 2016 wind forecasts for the wind resources
8 owned by PSE given several years of actual data and (ii) acquired a 2016 wind
9 forecast for Klondike III from Avangrid, the owner of that project. The new
10 forecasts provide the best, most current estimate of the long term expected energy
11 production for each resource.

12 **Q. How has actual wind generation compared to each of the preconstruction
13 wind forecasts, the 2010 DNV wind forecasts, and the 2016 wind forecasts?**

14 A. Actual wind production has been consistently below the levels estimated in both
15 the preconstruction and 2010 DNV wind forecasts. Table 2 below presents
16 average annual wind production for the life of each plant in comparison with the
17 previous forecasts. This data indicates that, on average, wind production has been
18 below the levels forecasted by 8.6 percent.

Table 2. Forecasted and Actual Annual Wind Generation (MWh)

Resource	Prior Forecast*	Historical Average	Variance	Percent Variance
Hopkins Ridge	████████	████████	████████	-9.4%
Wild Horse	████████	████████	████████	-3.7%
Wild Horse Expansion	████████	████████	████████	-5.5%
Lower Snake River	████████	████████	████████	-10.2%
Klondike III	████████	████████	████████	-18.2%
Total	████████	████████	████████	-8.6%

* 2010 DNV forecast for Hopkins Ridge, Wild Horse and Wild Horse Expansion. Preconstruction forecasts for Lower Snake River. Prior owner’s forecast for Klondike III.

1 The Third Exhibit to the Prefiled Rebuttal Testimony of Paul K. Wetherbee,
 2 Exh. PKW-18C, presents comparisons of actual wind generation with the
 3 preconstruction, 2010 DNV, and 2016 wind forecasts for each resource, using
 4 historical wind data that dates to the first full year of operations for each resource.
 5 These charts illustrate that the variation from forecasts has been persistent in
 6 most, if not all, years of operation of each resource.

7 **Q. How do historical capacity factors compare with those presented in the**
 8 **preconstruction forecasts and the 2016 wind forecasts?**

9 A. The Fourth Exhibit to the Prefiled Rebuttal Testimony of Paul K. Wetherbee,
 10 Exh. PKW-19C, presents the following capacity factors³¹ for each resource:
 11 (i) the capacity factor presented in the preconstruction forecasts; (ii) the capacity
 12 factor presented in the 2010 DNV wind forecasts; (iii) the capacity factor

³¹ A capacity factor is “the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.” U.S. Energy Information Administration, Glossary, available at <https://www.eia.gov/tools/glossary/index.php?id=C>.

1 presented in the 2016 wind forecasts used by PSE; and (iv) actual capacity factors
2 that use historical wind data for all full years of operation. As presented in the
3 exhibit, actual generation for each resource is below the levels forecasted in both
4 the preconstruction forecasts and the 2010 DNV wind forecasts.

5 **Q. Has PSE provided the 2016 Vaisala forecasts?**

6 A. Yes. The Fifth Exhibit to the Prefiled Rebuttal Testimony of Paul K. Wetherbee,
7 Exh. PKW-20C, contains the Vaisala forecasts for all of PSE's owned wind
8 resources. Vaisala provided its forecast reports to PSE in October 2016, and after
9 PSE reviewed the reports, Vaisala provided amended versions in July 2017. These
10 amended versions provided in Exhibit PKW-20C reflect corrections to
11 descriptions of the term of historical data used and treatment of curtailment and
12 availability losses. The generation forecasts remain unchanged from the October
13 2016 reports.

14 **B. Response to Staff Concerns About PSE's Proposal**

15 **Q. Has any party challenged PSE's use of the 2016 wind forecasts in this**
16 **proceeding?**

17 A. Yes. Commission Staff challenges PSE's use of the 2016 wind forecasts.
18 Commission Staff also opposes using the forecasts currently reflected in rates and
19 previously used in each of the 2011 GRC, the 2013 PCORC, the 2014 PCORC,
20 and the 2016 Power Cost Update. No other party raised objections to PSE's use of
21 the 2016 wind forecasts.

1 **Q. What wind forecast does Commission Staff recommend for use in this**
2 **proceeding?**

3 A. Commission Staff proposes the use of original preconstruction capacity factors in
4 the AURORA model for each of Hopkins Ridge, Wild Horse, Wild Horse
5 Expansion, LSR, and Klondike III.³²

6 **Q. What concerns did Commission Staff raise about PSE's use of 2016 wind**
7 **forecasts in this proceeding?**

8 A. Commission Staff's testimony (i) argues that PSE did not provide ample evidence
9 that reduced capacity factors are necessary;³³ (ii) criticizes the quality of the 2016
10 wind forecasts provided by Vaisala;³⁴ (iii) questions the consistency of the
11 2016 wind forecasts with PSE's 2015 IRP;³⁵ (iv) recommends that "wind
12 generation capacity factors should be based on the long term mean (P50) where
13 the risk and reward for under-and over-generation have an equal probability of
14 occurrence;"³⁶ and (v) presents the inclusion of wind integration costs as evidence
15 against updating the 2016 wind forecast.³⁷

³² See Gomez, Exh. DCG-1CT at 31:2-4; *see also id.* at 33:9-15. Hopkins Ridge forecast is the preconstruction forecast reflecting 2005 and 2007 adjustments.

³³ Gomez, Exh. DCG-1CT at 26:6-12.

³⁴ Gomez, Exh. DCG-1CT at 31:4-13.

³⁵ Gomez, Exh. DCG-1CT at 31:16-18.

³⁶ Gomez, Exh. DCG-1CT at 32:1-3.

³⁷ Gomez, Exh. DCG-1CT at 32:5-7.

1 **1. 2016 Vaisala Forecasts are Quality Forecasts**

2 **Q. What were Commission Staff’s concerns about the 2016 wind forecasts**
3 **provided by Vaisala?**

4 A. Commission Staff questioned (i) the use of monthly average data rather than 10-
5 minute supervisory control and data acquisition (“SCADA”) data, (ii) whether
6 SCADA data had been examined to determine whether the plants are operating
7 within their expected parameters, (iii) whether the 2016 wind studies accounted
8 for the 2015 El Niño, and (iv) the impacts to performance of the advancing age of
9 Hopkins Ridge turbines and how rate year O&M costs may mitigate those
10 impacts.³⁸

11 **Q. Why did Vaisala use monthly average data rather than 10-minute SCADA**
12 **data for the 2016 wind forecasts?**

13 A. The primary purpose of an operational reforecast is to provide an updated view on
14 expected long-term production. The Vaisala study develops an understanding of
15 the long-term mean and seasonal profile, and monthly generation data are a
16 primary input into the analysis. To generate the monthly generation data, PSE
17 aggregated the SCADA data accordingly.

³⁸ Gomez, Exh. DCG-1CT at 31:4-13.

1 **Q. Did PSE or Vaisala examine SCADA data to determine whether plants are**
2 **operating within their expected parameters?**

3 A. Yes. PSE examined this data. Comparisons with prior forecasts are presented in
4 Exhibits PKW-18C and PKW-19C.

5 **Q. Did the 2016 wind forecasts account for the 2015 El Niño?**

6 A. Yes. The 2016 wind forecasts accounted for the 2015 El Niño. One of the features
7 of the operational reforecast is that the analysis provides a long-term view of past
8 climate variability at a project site. Indeed, Vaisala's model simulations start in
9 1980, and Vaisala is able to capture the wind resource variability associated with
10 each El Niño or La Niña that has occurred over the past 37 years.

11 **2. Other Concerns about Forecast Update**

12 **Q. How do rate year O&M costs mitigate the performance impacts of the**
13 **advancing age of turbines?**

14 A. PSE's wind turbine O&M program mitigates for the degradation of turbine
15 physical condition. The operational condition of the turbines is monitored and
16 corrections made as needed under the terms of long-term maintenance agreements
17 with the turbine manufacturers. These agreements include (i) specific service
18 obligations and performance incentives for the early identification and resolution
19 of performance-degrading conditions; (ii) optimization of the timing and duration
20 of maintenance outages; (iii) warranty-like replacement coverage for mechanical,
21 electrical, or control system faults in each turbine; and (iv) select performance

1 enhancements. PSE's wind turbines have achieved an availability score (a
2 measure of their readiness to produce power) of between 97 to 99 percent, which
3 demonstrates the value of comprehensive maintenance, close collaboration
4 between PSE and the turbine manufacturer, and a long-term operations strategy.
5 In short, PSE's wind turbines have strong availability scores, but the wind has not
6 blown as frequently as originally anticipated to achieve the capacity factors for
7 these wind projects that was once thought possible.

8 **Q. Please describe Commission Staff's concern related to wind generation in the**
9 **2015 IRP.**

10 A. Commission Staff expresses difficulty reconciling PSE's use of the 2016 wind
11 forecasts in this proceeding with the description of assumed wind generation for
12 generic wind resources in the 2015 IRP.³⁹

13 **Q. Can PSE clarify the difference between the description of assumed wind**
14 **generation for generic wind resources in the 2015 IRP and the 2016 wind**
15 **forecast used by PSE in this proceeding?**

16 A. Yes. The section of the 2015 IRP to which Commission Staff's testimony refers
17 describes the input assumptions used by PSE for generic new wind construction
18 considered as potential resources in the 2015 IRP. The median capacity factor of
19 34 percent identified by Commission Staff⁴⁰ was an input assumption for generic

³⁹ Gomez, Exh. DCG-1CT at 31:16-18; *id.* at 31:fn. 57; *see* Mullally, Exh. MM-11 at 22-23.

⁴⁰ Gomez, Exh. DCG-1CT at 31:fn. 57.

1 resources used by PSE based on analysis provided by a third party expert rather
2 than an actual capacity factor for existing PSE resources. PSE used historical data
3 of Hopkins Ridge and Wild Horse to develop the distribution of energy
4 production, but not the capacity factors.

5 The characteristics of the generic resource assumed in the 2015 IRP are described
6 on page D-49 of the 2015 IRP.⁴¹ These characteristics reflect newer technologies
7 than PSE's current wind resources.

8 **Q. What data provides the long term mean, 50-percent exceedance level, for**
9 **annual energy production for each resource?**

10 A. The 2016 wind forecasts provide the best, most current estimate of the long term
11 mean, the 50-percent exceedance level, for annual energy production for each
12 resource. For example, the Vaisala study states as follows with respect to Wild
13 Horse: "The expected long-term mean potential net annual energy production
14 value, i.e. the net P50, is estimated to be 589.5 GWh."⁴² The energy projections
15 used by PSE in this proceeding reflect this level of expected energy production
16 for Wild Horse, and consistent estimates from the Vaisala forecasts for the other
17 resources.

⁴¹ Page D-49 states that "[w]hile the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding larger towers, wider rotor diameters, greater nameplate capacity and increased wind capture (efficiency). Commercially available machines are in the 2.0 to 3.0 MW range with hub heights of 80 to 100 meters and blade diameters topping out around 110 meters."

⁴² Wetherbee, Exh. PKW-20C at 66.

1 **Q. Is inclusion of wind integration costs a reason to continue to use**
2 **preconstruction wind forecasts to estimate power costs?**

3 A. No. The inclusion of wind integration costs is not a reason to continue to use
4 preconstruction wind forecasts to estimate power costs. Wind integration costs
5 account for the cost of balancing generation with load on an hour-ahead and day-
6 ahead basis. Wind integration costs are not a substitute for a good wind forecast
7 and do not account for the cost of the energy that is needed to replace assumed
8 wind energy that does not materialize.

9 **Q. Does Commission Staff raise other issues regarding wind forecasts that PSE**
10 **would like to address?**

11 A. Yes. Commission Staff raises three additional issues regarding wind forecasts that
12 PSE would like to address. First, Commission Staff suggests that “[t]he issue of
13 modeling wind production, for the purposes of setting rates, is akin to the
14 controversies which once surrounded hydro normalization.”⁴³ Second,
15 Commission Staff mischaracterizes the 2016 wind forecasts as “derates” of the
16 wind projects.⁴⁴ Third, Commission Staff measures the impact of the 2016 wind
17 forecasts based solely on PSE’s owned resources only and fails to include the
18 impact of the 2016 wind forecasts for Klondike III.

⁴³ Gomez, Exh. DCG-1CT at 27:fn. 51.

⁴⁴ Gomez, Exh. DCG-1CT at 28:1-12.

1 **Q. Does PSE agree that “[t]he issue of modeling wind production, for the**
2 **purposes of setting rates, is akin to the controversies which once surrounded**
3 **hydro normalization”?**⁴⁵

4 A. PSE would agree that the need to update preconstruction forecasts to reflect actual
5 generation is neither new nor unique to PSE. As mentioned in Commission Staff’s
6 testimony, PSE has previously relied upon the 2010 DNV wind forecasts to
7 update preconstruction forecasts for Hopkins Ridge and Wild Horse in the
8 2011 GRC, and PacifiCorp sought to update preconstruction forecasts to reflect
9 actual generation for four of its wind projects. If Commission Staff considers the
10 modeling of wind production to be akin to hydro normalization, then the proper
11 result should be the same for wind generation as for hydro normalization (i.e., the
12 use of historical average data over a long period of time). Historical energy
13 production is also used as the forecast for energy production for certain
14 Qualifying Facilities. For wind projects, use of historical average wind data would
15 be a reasonable alternative to forecasts.

16 **Q. Why does PSE state that Commission Staff mischaracterizes the 2016 wind**
17 **forecasts as “derates” of the wind projects?**

18 A. “Derate” has a specific and technical meaning, as defined by the North American
19 Electric Reliability Corporation (“NERC”). The NERC Generating Availability
20 Data System (“GADS”) Reporting Instructions define the word as follows: “A

⁴⁵ Gomez, Exh. DCG-1CT at 27:fn. 51.

1 derating exists whenever a unit is limited to a power level that is less than the
2 unit's net maximum capacity," and "a derate starts when a facility is not capable
3 of reaching 100% capacity."⁴⁶ In updating generation forecasts, PSE does not
4 propose a reduction to the plant capacity. Instead, the updated wind forecasts
5 reflect the fact that actual energy production has been below preconstruction
6 forecasts and the forecasts included in the 2010 DNV wind forecasts. These
7 updates do not reduce plant capacity.

8 **Q. How does the 2016 wind forecast for Klondike III impact power costs?**

9 A. Because the Klondike III power purchase agreement has a fixed price and the cost
10 is included in power costs, a reduction to the energy forecast reduces power costs,
11 which is the opposite effect of a reduction to the energy forecast of PSE-owned
12 resources. Although the Commission Staff testimony provides an estimate of the
13 power cost impact of the reduced energy from PSE's owned resources, it simply
14 mentions that the 2016 wind forecast for Klondike III is also lower but neglects to
15 mention that it partially offsets the power cost impacts of PSE's owned
16 resources.⁴⁷ The \$4.4 million increase estimated by Commission Staff overstates
17 the impact of updating wind forecasts by approximately \$2.3 million.

⁴⁶ North American Electric Reliability Corporation, *Generating Availability Data System Reporting Instructions*, available at http://www.nerc.com/files/Section_3_Event_Reporting.pdf.

⁴⁷ Gomez, Exh. DCG-1CT at 25:5-10.

1 **3. 2016 Forecasts Are Best Indicator of Future Generation**

2 **Q. Does PSE agree with Commission Staff’s proposal to return to**
3 **preconstruction forecasts?**

4 A. No. It is unclear to PSE why Commission Staff prefers preconstruction forecasts
5 to more current forecasts, including those forecasts currently reflected in rates
6 since 2012. Preconstruction forecasts reflect information available prior to plant
7 operation. By definition, preconstruction forecasts do not consider actual
8 generation. Table 3 below presents a summary of capacity factors from the
9 preconstruction forecasts proposed by Staff in comparison with historical actuals
10 and those proposed by PSE.

Table 3. Forecasted and Actual Wind Capacity Factors

Resource	Staff Proposal	Historical Average	PSE Proposal
Hopkins Ridge	█████%	█████%	█████%
Wild Horse	█████%	█████%	█████%
Wild Horse Expansion	█████%	█████%	█████%
Lower Snake River	█████%	█████%	█████%
Klondike III	█████%	█████%	█████%

11 As previously discussed, actual wind data for the projects have been consistently
12 below the preconstruction and 2010 DNV wind forecasts. It was reasonable for
13 PSE to obtain new forecasts from an outside expert. The 2016 wind forecasts
14 utilize historical data and current technologies for forecasting wind generation,
15 which are an improvement over the lack of data and technology available for
16 preconstruction wind forecasts. The 2016 wind forecasts provide the best current

1 estimate of energy production from the plants and are more representative of
2 actual results than prior forecasts.

3 **Q. Do the power costs presented by PSE in this rebuttal testimony rely on the**
4 **2016 wind forecasts?**

5 A. Yes. The 2016 wind forecasts provide the most current estimate of wind
6 generation based on current forecasting methods and several years of historical
7 data. If the Commission were to agree with Commission Staff and view wind
8 forecasts as akin to hydro normalization, then historical average wind data would
9 be a suitable alternative to forecasts.

10 **Q. How many years of actual wind data are available?**

11 A. The amount of actual wind data available varies by wind project. There are over
12 12 years of actual wind data available for Hopkins Ridge, over 10 years of actual
13 wind data available for Wild Horse, over seven years of actual wind data available
14 for Wild Horse Expansion, over five years of actual wind data available for Lower
15 Snake River, and nine years of actual wind data available for Klondike III.

16 **VI. DAY-AHEAD WIND INTEGRATION COSTS**

17 **Q. What data did PSE use to calculate its day-ahead wind integration costs?**

18 A. PSE used historical data from the beginning of plant operations through
19 December 2015 to calculate day-ahead wind integration costs. At the time that
20 PSE prepared its analysis for the initial filing, data for all of 2016 were not
21 available.

1 **Q. Does PSE agree with Commission Staff’s recommendation that PSE update**
2 **the day-ahead analysis to include 2016 data?**⁴⁸

3 A. Yes. PSE’s estimated rate year power costs in this rebuttal filing include an
4 updated estimate of day-ahead wind integration costs using data through the end
5 of calendar year 2016.

6 **Q. How did this change impact rate year power costs?**

7 A. Day-ahead wind integration costs changed from \$ [REDACTED] to \$ [REDACTED], a
8 decrease of \$ [REDACTED].

9 **VII. RECALCULATION OF POWER COSTS FOR THE**
10 **MICROSOFT SPECIAL CONTRACT**

11 **Q. Why has PSE recalculated power costs for the Microsoft special contract?**

12 A. PSE and Microsoft Corporation (“Microsoft”) have entered into a special contract
13 that allows Microsoft to acquire the majority of its energy from a source other
14 than PSE and become a retail wheeling customer of PSE. Therefore, Microsoft’s
15 special contract qualifying load (and PSE’s power costs to meet that load) need to
16 be removed from power cost calculations for purposes of calculating a new
17 baseline rate. PSE provided this contingent calculation of power costs in its
18 supplemental filing.

⁴⁸ Gomez, Exh. DCG-1CT at 14:13 – 15:4.

1 **Q. Have other parties raised concerns with respect to the removal of Microsoft's**
2 **special contract qualifying load (and PSE's power costs to meet that load)**
3 **from power cost calculations for purposes of calculating a new baseline rate?**

4 A. Although no party raised issues with respect to the calculation performed by PSE,
5 Commission Staff opposed the timing of this analysis. Commission Staff
6 recommends against inclusion of a contingent calculation of power costs to
7 account for Microsoft's partial change to retail wheeling in this proceeding.
8 Instead, Commission Staff expresses a preference for an update if and when
9 Microsoft takes generation from a source other than PSE. The reasons for this
10 preference include concerns that (i) gas and power prices will change (and the
11 calculation should be made with then-existing prices at the time that Microsoft
12 becomes a retail wheeling customer for the majority of its load) and (ii) any
13 modifications to PSE's power costs in this proceeding ordered by the Commission
14 should also be reflected in the contingent calculation.⁴⁹

15 **Q. Does PSE agree that the contingent calculation should be developed when**
16 **Microsoft changes to retail wheeling for the majority of its load, based on gas**
17 **prices other than those used in this proceeding?**

18 A. No. PSE does not agree that the contingent calculation should be developed when
19 Microsoft changes to retail wheeling for the majority of its load, based on gas
20 prices other than those used in this proceeding. Power costs projections are based

⁴⁹ Gomez, Exh. DCG-1CT at 33:19 – 35:10.

1 on a set of input assumptions that are inter-related and cannot easily be separated.

2 These include resources, contracts, rate year load, and forward gas prices.

3 Attempts to update power costs by modifying only one or two of these

4 assumptions after a rate period has begun generate inconsistency. A partial update

5 opens up questions of what should and should not be changed. For example:

- 6 • Would prices be a combination of actuals for part of the
7 rate year and forwards for the remainder of the rate year, or
8 forwards for a different rate year?
- 9 • If prices from a different rate year were used, should load,
10 contracts and resources all be changed to reflect the new
11 rate year?
- 12 • Since resources and contracts for a revised rate year would
13 be different from those approved in this proceeding, should
14 those changes be allowed without the opportunity for
15 review by the parties in this proceeding and the
16 Commission?
- 17 • If the rate year is not changed but is underway, should
18 actual costs be used in place of projected costs for a portion
19 of the rate year?

20 Prices cannot be updated once the rate year has begun without opening up these
21 questions. Input assumptions, including gas prices, are inter-related, and updating
22 one assumption without updating all power costs creates inconsistency. It is much
23 more straightforward to estimate power costs that reflect the Microsoft special
24 contract during this proceeding than to do it later once the rate year is in progress.

1 **Q. Why did PSE file a partial update to power costs in the 2016 Power Cost**
2 **Update?**

3 A. In the 2016 Power Cost Update, the Commission authorized PSE to make a
4 compliance filing related to the contracted increases in capacity in the Centralia
5 Coal Transition Power Purchase Agreement. As discussed in Commission Staff's
6 testimony, PSE was obligated to file a general rate case between April 1, 2015,
7 and April 1, 2016, pursuant to Order 7 in Dockets UE-121697, *et al.* In the joint
8 petition to modify Order 7, Joint Petitioners petitioned the Commission to extend
9 the date for PSE to file its general rate case to no later than January 17, 2017. The
10 Commission granted this request, the terms of which included the following:

11 The previously authorized Centralia compliance filing to be made
12 by PSE on or before October 1, 2016, will include a limited update
13 to variable power costs with updated rates in Schedule 95 and the
14 updated PCA baseline rate to go into effect on December 1,
15 2016.⁵⁰

16 In short, this was a special case in which PSE agreed to a limited power costs
17 update.

18 **Q. Will PSE update the contingent calculation as part of its compliance filing in**
19 **this proceeding to reflect any changes order by the Commission to its power**
20 **costs analysis?**

21 A. Yes. The intent of the contingent calculation is that it be consistent with the final
22 costs approved in this proceeding. The Ninth Exhibit to the Prefiled Rebuttal

⁵⁰ *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697, *et al.*, Joint Petition to Modify Order 07 ¶ 8.

1 Testimony of Paul K. Wetherbee, Exh. PKW-24C, provides projected power costs
2 presented in this rebuttal testimony with the Microsoft special contract qualifying
3 load removed. PSE proposes to update this calculation again with the compliance
4 filing in this proceeding.

5 VIII. UPDATED POWER COSTS

6 **Q. Have you provided an update to power costs?**

7 A. Yes. The Sixth Exhibit to the Prefiled Rebuttal Testimony of Paul K. Wetherbee,
8 Exh. PKW-21C, provides an updated summary of power costs. The Seventh
9 Exhibit to the Prefiled Rebuttal Testimony of Paul K. Wetherbee, Exh. PKW-
10 22C, provides a comparison of (i) projected power costs presented in this rebuttal
11 testimony with (ii) the projected power costs presented in PSE's supplemental
12 testimony filed on April 3, 2017. The Eighth Exhibit to the Prefiled Rebuttal
13 Testimony of Paul K. Wetherbee, Exh. PKW-23C, provides a comparison of
14 (i) projected power costs presented in this rebuttal testimony with (ii) the
15 projected power costs presented in the 2016 Power Costs Update. As previously
16 mentioned, the Ninth Exhibit to the Prefiled Rebuttal Testimony of Paul K.
17 Wetherbee, Exh. PKW-24C, provides projected power costs presented in this
18 rebuttal testimony with the Microsoft special contract qualifying load removed.
19 The Tenth Exhibit to the Prefiled Rebuttal Testimony of Paul K. Wetherbee,
20 Exh. PKW-25C, provides a comparison of (i) projected power costs presented in
21 this rebuttal testimony with the Microsoft qualifying load removed with

1 (ii) projected power costs presented in PSE’s supplemental testimony filed on
2 April 3, 2017, with the Microsoft special contract qualifying load removed.

3 **Q. What changes did PSE make to the AURORA model database for this**
4 **rebuttal filing?**

5 A. PSE updated the AURORA model database for:

- 6 (i) three-month average forward gas prices at June 23, 2017
7 and the short-term rate year power hedges as of the same
8 date;
- 9 (ii) an update to the Colstrip fuel and variable dispatch costs
10 based on updated Colstrip budgets;
- 11 (iii) an update to reflect the final power purchase agreement
12 with Public Utility District No. 1 of Douglas County,
13 Washington (“Douglas PUD”) for output from the Wells
14 Hydroelectric Project effective September 1, 2018.
15 Projected rate year power costs reflect an increase in PSE’s
16 allocation from 32.07 percent in the initial filing to an
17 average of 32.47 percent in the last four months of the
18 2018 rate year;
- 19 (iv) an update to include energy and costs from one new
20 Schedule 91 contract that started providing energy to PSE
21 in April 2017;
- 22 (v) an update to the run setup to remove modeling logic related
23 to compliance with the Clean Air Rule; and
- 24 (vi) an update to the model run setup to remove the option
25 selection of “Use Operating Reserves.”

26 **Q. What changes did PSE make to forecast power costs outside of the AURORA**
27 **model for this rebuttal filing?**

28 A. PSE’s adjusted costs outside of the AURORA model—the Costs Not in
29 AURORA—include:

- 1 (i) an update to forecasted fixed gas transport costs to reflect
2 the updated rates charged to PSE for upstream pipeline
3 costs by Northwest Pipeline, Westcoast, and Nova and to
4 correct nonmaterial errors in the original filing;
- 5 (ii) the mark-to-market calculation for gas for power contracts
6 in place at June 23, 2017, which also included updating the
7 basis differential forecast for the rate year;
- 8 (iii) an update to the rate year Colstrip fixed costs to reflect
9 updated Colstrip budgets;
- 10 (iv) an update to reflect fixed and variable costs from the final
11 power purchase agreement with Douglas PUD for output
12 from the Wells Hydroelectric Project effective
13 September 1, 2018 and to correct a fixed costs calculation
14 error in the original filing;
- 15 (v) updated rate year budget information for PSE’s Mid-
16 Columbia (“Mid-C”) contracts with Douglas PUD for the
17 output from the Wells Hydroelectric Project, with Public
18 Utility District No. 1 of Chelan County, Washington for the
19 output from the Rocky Reach and Rock Island
20 Hydroelectric Projects and with Public Utility District
21 No. 2 of Grant County, Washington for output from the
22 Wanapum and the Priest Rapids Hydroelectric Projects;
- 23 (vi) an update to reflect an updated approach to estimating the
24 impacts of the Clean Air Rule on rate year power costs; and
- 25 (vii) other Costs Not in AURORA changes to reflect the updated
26 AURORA dispatch and lower forecast market prices.

27 **Q. Did PSE update transmission rates for service from Bonneville Power**
28 **Administration (“BPA”) in its projection of power costs in this rebuttal**
29 **filing?**

30 A. No. PSE continued to use the projected BPA transmission rates that were used in
31 the initial filing. On July 26, 2017, BPA released the Administrator’s Final

1 Record of Decision,⁵¹ which establishes new BPA rates effective October 1, 2017.
2 PSE had completed its power costs analysis for this rebuttal filing prior to BPA's
3 release of the Administrator's Final Record of Decision. PSE will update the BPA
4 transmission rates in its power costs projections in the compliance filing in this
5 proceeding. PSE estimates the new BPA transmission rates will result in
6 approximately a \$500,000 reduction to power costs.

7 **Q. What level of power costs does PSE propose in this rebuttal filing?**

8 A. PSE proposes total power costs of \$714.9 million in this rebuttal filing. This is a
9 reduction of \$22.9 million (3.1 percent) from the power costs in the supplemental
10 filing and an increase of \$0.8 million (0.1 percent) from rates approved in the
11 2016 Power Cost Update and currently in place.

12 **Q. What caused the reduction in power costs from the supplemental filing?**

13 A. The two major factors that caused the reduction in power costs are a reduction in
14 forward natural gas prices and the change to PSE's approach to estimating costs
15 of compliance with the Clean Air Rule.

16 Average rate year gas prices declined from \$2.55/MMBtu in the supplemental
17 filing to \$2.48/MMBtu in this rebuttal filing. PSE removed the emissions limits
18 on its combined cycle resources in favor of making an adjustment to power costs
19 outside of AURORA. Together, these changes resulted in reductions to the

⁵¹ BPA, Administrator's Final Record of Decision, BP-18-A-04 (July 26, 2017), available at <https://www.bpa.gov/secure/Ratecase/openfile.aspx?fileName=BP-18-A-04+Final+ROD.pdf&contentType=application%2fpdf>.

1 AURORA-generated market power prices. In combination, all of these changes
2 resulted in increased utilization of the combined cycle resources, reduced market
3 purchases, and reduced power costs.

4 Other factors that contributed to the reduction are updates to upstream pipeline
5 transportation rates, Colstrip and Mid-C hydro budgets, and rate year hedges.

6 Table 4 below presents a summary of changes from the supplemental filing.

**Table 4. Power Cost Changes from Supplemental Filing
(dollars in thousands)**

Supplemental power costs	\$737,710
+ Change in gas price	(\$5,911)
+ Change in Clean Air Rule modeling	(\$15,764)
+ Change in pipeline rates	(\$1,518)
+ Other changes	\$340
<hr/>	
Rebuttal power costs	\$714,857

7 **Q. How did the power costs in the recalculation for the Microsoft special**
8 **contract change from the supplemental filing?**

9 A. The power costs declined from \$714.9 million in the supplemental filing to
10 \$ [REDACTED] million in this rebuttal filing.

11 **IX. CONCLUSION**

12 **Q. Does this conclude your rebuttal testimony?**

13 A. Yes.