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

**BEFORE THE**

**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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| --- | --- | --- |
| **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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**PUGET SOUND ENERGY**

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

**I. INTRODUCTION**

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

A. Yes I am.

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

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

(i) PSE’s approach to estimating the impacts of the Clean Air Rule on rate year power costs;

(ii) Treatment of costs and benefits of PSE’s participation in the California Independent System Operator (“CAISO”) Energy Imbalance Market;

(iii) Input assumptions for PSE’s gas fired resources, including variable operating and maintenance expenses and major maintenance costs;

(iv) The wind forecast used to estimate power costs;

(v) The historical data used to calculate day ahead wind integration costs; and

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

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

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

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

**II. CLEAN AIR RULE**

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

A. As described in my prefiled direct testimony,[[1]](#footnote-2) PSE estimated emissions limits for the resources that are likely to have limits given descriptions in the rule, which are the combined cycle plants. PSE calculated the limits by plant based on Washington State Department of Ecology (“Ecology”) data from 2012 through 2015 and descriptions in the rule of how Ecology will calculate emissions limits for stationary sources. PSE used data through 2015 because 2016 data were not complete at the time PSE prepared its initial filing. PSE placed these emissions limits in its AURORA model. The limits resulted in reduced output from the combined cycle resources than would have been indicated absent the caps. PSE also made some downstream adjustments to Not in Aurora costs.

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

A. Commission Staff and ICNU oppose inclusion of any costs related to the Clean Air Rule. No other party commented on PSE’s treatment of the Clean Air Rule.

Commission Staff argues that (i) PSE’s baseline emission limits are not known;[[2]](#footnote-3) (ii) PSE’s analysis results in over-compliance with the Clean Air Rule;[[3]](#footnote-4) (iii) the restriction of individual resources rather than the aggregate resources misrepresents the Clean Air Rule;[[4]](#footnote-5) (iv) PSE should not make assumptions about the emissions limits of other parties;[[5]](#footnote-6) and (v) there are other ways to comply with the rule, including offsetting emissions by purchase of emissions reduction units (“ERUs”) as described in the rule.[[6]](#footnote-7)

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

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

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

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

(ii) At least three years of covered GHG emissions subject to (b) of this subsection.[[7]](#footnote-8)

Using this guideline, PSE was able to calculate its baseline emissions values. Commission Staff’s testimony refers to WAC 173-442-050(3) as evidence that Ecology has discretion to exclude up to two years of data to calculate baselines. However, WAC 173-442-050(3)(b) provides Ecology the discretion to exclude a year of data only under two circumstances—(i) if a facility was in a period of curtailment during a calendar year, or (ii) if the methodology to calculate emissions by the facility changes and the variance between old and new is greater than fifteen percent without any change to general operating conditions:

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

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

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

(B) The GHG emissions calculation methodology produced a fifteen percent or more difference between that calendar year's GHG emissions and the 2012 through 2016 average of GHG emissions using the methodology in (a) of this subsection; and

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

(ii) The calendar year contains a period of curtailment.[[8]](#footnote-9)

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

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

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

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

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

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

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **2012-2015AveragePSE InitialFiling\*** | **2012-2016AverageNo OutliersRemoved** | **2012-2016Average+-15% OutliersRemoved** | **2012-2016Average+-20% OutliersRemoved** |
| Total PSE Plant Emissions (metric tons CO2e) – 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 CO2e) – 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. |

Commission Staff asserts that “baseline estimates might vary by as much as 5 percent,”[[9]](#footnote-10) but the highest variance presented in Commission Staff’s table is 3.6 percent.[[10]](#footnote-11) As previously stated, the applicable rule requires Ecology to use five years of data except under two circumstances, neither of which applies to PSE’s resources. Therefore, Commission Staff’s assertion that baseline estimates could vary significantly from PSE’s estimates is speculative.

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

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

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

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

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

A. Renewable energy credits (“RECs”) can be converted to ERUs pursuant to WAC 173-442-160(5)(b). PSE estimated a price for 2018-19 RECs eligible to be used for compliance with Washington’s renewable portfolio standard (“RPS”) based on market prices. This REC price is $███/REC with a conversion of 2.25 RECS per ERU consistent with WAC 173-442-160(5)(c)(i)(C).

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

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

**Q. Could ERU prices increase?**

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

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

A. In its Final Cost-Benefit and Least-Burdensome Alternative Analysis[[12]](#footnote-13), Ecology presented a range of ERU costs of $3 to $57 per metric ton (“MT”) of CO2e, with one MT being equivalent to one ERU, based on the alternative options for compliance with the rule. The $███/REC translates to $███/MT CO2e based on Ecology’s conversion factor of 2.25 RECs per ERU. The price assumed by PSE is in the bottom quartile of Ecology’s range. The wide range of estimates provided by Ecology is evidence of the price risk associated with ERUs discussed above and indicates that PSE’s price assumption is moderate.

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

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

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

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

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

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

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

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

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

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

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

**III. ENERGY IMBALANCE MARKET**

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

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

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

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

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

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

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

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

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

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

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

In approving Pacific Power’s proposal, we are allowing Pacific Power to include fixed costs related to the EIM in the actual power costs in its annual PCAM filing, but we do not approve their inclusion indefinitely. Pacific Power, in its next general rate case, must remove the EIM fixed costs from the PCAM’s annual true-up and propose their recovery in non-power cost rates. The Commission will determine at that time if the costs are commensurate with the benefits.[[15]](#footnote-16)

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

**Q. Will PSE get cost recovery of Energy Imbalance Market related costs given Staff’s proposal as Staff asserts?[[16]](#footnote-17)**

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

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

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

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

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

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

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

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

A. As indicated in my prefiled direct testimony,[[18]](#footnote-19) PSE used O&M costs established by CAISO to model the dispatch of all gas-fired resources in AURORA except for the Encogen Generating Station (“Encogen”). For Encogen, PSE used a calculated cost based on three years of historical data. PSE also used estimated major maintenance costs as hurdles to unit commitment and dispatch in the AURORA analysis. The major maintenance costs were developed based on PSE data and negotiations with CAISO. Both the CAISO variable O&M and major maintenance costs are also used for PSE’s daily operational unit commitment and dispatch decisions. Table 16 of my prefiled direct testimony also presents PSE calculated variable O&M based on three years of historical data, for comparison purposes.[[19]](#footnote-20)

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

A. No. As explained in my prefiled direct testimony,[[20]](#footnote-21) O&M costs are not part of power costs. They are relevant to the unit commitment and dispatch decisions because those decisions are based on the relative costs of purchasing power versus generating power, and O&M costs are part of that economic decision.

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

A. Commission Staff objects to PSE’s use of CAISO variable O&M and the inclusion of major maintenance costs in its unit commitment and dispatch logic to project power costs in this proceeding.[[21]](#footnote-22) Commission Staff also criticizes the PSE calculated variable O&M presented in Table 16 of my prefiled direct testimony on the grounds that it relied on plant costs and generation data from 2013-2015 that predates the test year.[[22]](#footnote-23)

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

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

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

A. Commission Staff proposes use of (i) variable O&M based on test year actual costs and (ii) no major maintenance costs to model unit commitment and dispatch decisions.[[23]](#footnote-24)

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

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

Variable O&M costs come in chunks. While these costs depend on generation, they do not correspond directly to the level of energy production in a given twelve month period. A plant might require parts for a corrective maintenance event one year, and have much lower maintenance costs the next year. Energy also varies from year to year. When costs are divided by energy, the resulting cost per megawatt-hour (MWh) can be much different in one year compared to the next. Normalized variable O&M costs are a better input to the unit commitment and dispatch logic, and are more consistent with PSE operations and with treatment of production O&M costs in rates than test year variable O&M.

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

A. Yes. As stated in Commission Staff’s testimony, the treatment of production O&M costs is largely uncontroversial.[[24]](#footnote-25) Since the Commission’s order in the 2013 PCORC, PSE has deferred and amortized major maintenance costs for the gas-fired resources.

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

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

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

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

A. Yes. A three-year average of actual variable O&M costs calculated based on historical plant data could serve as a suitable alternative. PSE has presented these costs in Table 16 of my prefiled direct testimony.[[25]](#footnote-26) A three-year average would smooth out the peaks and valleys in costs.

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

A. In calculating power costs for this rebuttal filing, PSE used the three-year average variable O&M based on data from PSE’s resources, with two small modifications.

First, net generation for Encogen was unavailable for all months when PSE originally made the calculations. As mentioned in Commission Staff’s testimony,[[26]](#footnote-27) PSE substituted Encogen gross generation data for months missing Encogen net generation data. PSE has since recalculated variable O&M for Encogen using net generation for all months. This update results in an increase from $███/MWh to $███/MWh.

PSE’s analysis does not include variable O&M for Ferndale Generating Station (“Ferndale”). In the initial filing in this proceeding, PSE used the CAISO variable O&M cost in its analysis. To estimate power costs in this rebuttal filing, PSE used the variable O&M cost for Sumas Generating Station (“Sumas”) as a proxy for Ferndale.

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

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

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

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

A. The major maintenance adder is an estimate of PSE’s major maintenance costs, modeled in AURORA on a dollars/start basis for simple cycle resources and a dollars/MWh basis for combined cycle resources, as stated in my prefiled direct testimony. These are different from the corrective maintenance costs included in variable O&M. PSE included them in its unit commitment and dispatch logic in projecting power costs because these costs are incurred based on the amount of run time and the number of starts for a resource. Operationally, PSE uses these costs in the economic unit commitment and dispatch decisions. PSE participates in the CAISO market, and it is standard in the industry to include these costs in economic decisions.

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

A. Commission Staff asserts that (i) inclusion of major maintenance in the dispatch logic is double-counting of costs because there is an out-of-model adjustment for these costs, (ii) PSE did not provide evidence that use of major maintenance costs better characterizes unit commitment and dispatch of its gas-fired resources, and (iii) use of major maintenance costs for modeling contradicts Commission input provided in the 2015 Integrated Resource Plan (“2015 IRP”).[[27]](#footnote-28)

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

A. No. The power costs adjustment related to major maintenance costs in “Costs not in Aurora” is to remove non-fuel startup costs of the simple cycle gas-fired resources. As discussed in my prefiled direct testimony, AURORA considers startup costs in the unit commitment decision and includes these costs in fuel cost of simple cycle combustion turbines. The adjustment is necessary to remove these costs because they are variable O&M rather than power costs. For the rebuttal filing, this is a decrease of $███ to AURORA-generated power costs. The purpose of this adjustment is to prevent double-counting of major maintenance related startup costs for simple cycle gas-fired resources.

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

A. Commission Staff’s testimony quotes a section of the Commission’s acknowledgement letter of the 2015 IRP,[[28]](#footnote-29) in which the Commission stated that zero energy output from peaking resources over a 20-year planning horizon was unreasonable. This result was attributed to inclusion of major maintenance costs in variable O&M.[[29]](#footnote-30)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Q. Do you agree with Commission Staff’s assertion that use of test year variable O&M and removal of the major maintenance hurdle in the dispatch logic in calculating power costs would reduce power costs by $6.1 million?[[30]](#footnote-31)**

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

**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 2016wind 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 2016wind 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”).

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

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

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

A. Actual wind production has been consistently below the levels estimated in both the preconstruction and 2010 DNV wind forecasts. Table 2 below presents average annual wind production for the life of each plant in comparison with the previous forecasts. This data indicates that, on average, wind production has been 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. |

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

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

A. The Fourth Exhibit to the Prefiled Rebuttal Testimony of Paul K. Wetherbee, Exh. PKW-19C, presents the following capacity factors[[31]](#footnote-32) for each resource: (i) the capacity factor presented in the preconstruction forecasts; (ii) the capacity factor presented in the 2010 DNV wind forecasts; (iii) the capacity factor presented in the 2016 wind forecasts used by PSE; and (iv) actual capacity factors that use historical wind data for all full years of operation. As presented in the exhibit, actual generation for each resource is below the levels forecasted in both the preconstruction forecasts and the 2010 DNV wind forecasts.

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

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

**B. Response to Staff Concerns About PSE’s Proposal**

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

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

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

A. Commission Staff proposes the use of original preconstruction capacity factors in the AURORA model for each of Hopkins Ridge, Wild Horse, Wild Horse Expansion, LSR, and Klondike III.[[32]](#footnote-33)

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

A. Commission Staff’s testimony (i) argues that PSE did not provide ample evidence that reduced capacity factors are necessary;[[33]](#footnote-34) (ii) criticizes the quality of the 2016 wind forecasts provided by Vaisala;[[34]](#footnote-35) (iii) questions the consistency of the 2016 wind forecasts with PSE’s 2015 IRP;[[35]](#footnote-36) (iv) recommends that “wind generation capacity factors should be based on the long term mean (P50) where the risk and reward for under-and over-generation have an equal probability of occurrence;”[[36]](#footnote-37) and (v) presents the inclusion of wind integration costs as evidence against updating the 2016 wind forecast.[[37]](#footnote-38)

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

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

A. Commission Staff questioned (i) the use of monthly average data rather than 10-minute supervisory control and data acquisition (“SCADA”) data, (ii) whether SCADA data had been examined to determine whether the plants are operating within their expected parameters, (iii) whether the 2016 wind studies accounted for the 2015 El Niño, and (iv) the impacts to performance of the advancing age of Hopkins Ridge turbines and how rate year O&M costs may mitigate those impacts.[[38]](#footnote-39)

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

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

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

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

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

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

**2. Other Concerns about Forecast Update**

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

A. PSE’s wind turbine O&M program mitigates for the degradation of turbine physical condition. The operational condition of the turbines is monitored and corrections made as needed under the terms of long-term maintenance agreements with the turbine manufacturers. These agreements include (i) specific service obligations and performance incentives for the early identification and resolution of performance-degrading conditions; (ii) optimization of the timing and duration of maintenance outages; (iii) warranty-like replacement coverage for mechanical, electrical, or control system faults in each turbine; and (iv) select performance enhancements. PSE’s wind turbines have achieved an availability score (a measure of their readiness to produce power) of between 97 to 99 percent, which demonstrates the value of comprehensive maintenance, close collaboration between PSE and the turbine manufacturer, and a long-term operations strategy. In short, PSE’s wind turbines have strong availability scores, but the wind has not blown as frequently as originally anticipated to achieve the capacity factors for these wind projects that was once thought possible.

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

A. Commission Staff expresses difficulty reconciling PSE’s use of the 2016 wind forecasts in this proceeding with the description of assumed wind generation for generic wind resources in the 2015 IRP.[[39]](#footnote-40)

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

A. Yes. The section of the 2015 IRP to which Commission Staff’s testimony refers describes the input assumptions used by PSE for generic new wind construction considered as potential resources in the 2015 IRP. The median capacity factor of 34 percent identified by Commission Staff[[40]](#footnote-41) was an input assumption for generic resources used by PSE based on analysis provided by a third party expert rather than an actual capacity factor for existing PSE resources. PSE used historical data of Hopkins Ridge and Wild Horse to develop the distribution of energy production, but not the capacity factors.

The characteristics of the generic resource assumed in the 2015 IRP are described on page D-49 of the 2015 IRP.[[41]](#footnote-42) These characteristics reflect newer technologies than PSE’s current wind resources.

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

A. The 2016 wind forecasts provide the best, most current estimate of the long term mean, the 50-percent exceedance level, for annual energy production for each resource. For example, the Vaisala study states as follows with respect to Wild Horse: “The expected long-term mean potential net annual energy production value, i.e. the net P50, is estimated to be 589.5 GWh.”[[42]](#footnote-43) The energy projections used by PSE in this proceeding reflect this level of expected energy production for Wild Horse, and consistent estimates from the Vaisala forecasts for the other resources.

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

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

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

A. Yes. Commission Staff raises three additional issues regarding wind forecasts that PSE would like to address. First, Commission Staff suggests that “[t]he issue of modeling wind production, for the purposes of setting rates, is akin to the controversies which once surrounded hydro normalization.”[[43]](#footnote-44) Second, Commission Staff mischaracterizes the 2016 wind forecasts as “derates” of the wind projects.[[44]](#footnote-45) Third, Commission Staff measures the impact of the 2016 wind forecasts based solely on PSE’s owned resources only and fails to include the impact of the 2016 wind forecasts for Klondike III.

**Q. Does PSE agree that“[t]he issue of modeling wind production, for the purposes of setting rates, is akin to the controversies which once surrounded hydro normalization”?[[45]](#footnote-46)**

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

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

A. “Derate” has a specific and technical meaning, as defined by the North American Electric Reliability Corporation (“NERC”). The NERC Generating Availability Data System (“GADS”) Reporting Instructions define the word as follows: “A derating exists whenever a unit is limited to a power level that is less than the unit’s net maximum capacity,” and “a derate starts when a facility is not capable of reaching 100% capacity.”[[46]](#footnote-47) In updating generation forecasts, PSE does not propose a reduction to the plant capacity. Instead, the updated wind forecasts reflect the fact that actual energy production has been below preconstruction forecasts and the forecasts included in the 2010 DNV wind forecasts. These updates do not reduce plant capacity.

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

A. Because the Klondike III power purchase agreement has a fixed price and the cost is included in power costs, a reduction to the energy forecast reduces power costs, which is the opposite effect of a reduction to the energy forecast of PSE-owned resources. Although the Commission Staff testimony provides an estimate of the power cost impact of the reduced energy from PSE’s owned resources, it simply mentions that the 2016 wind forecast for Klondike III is also lower but neglects to mention that it partially offsets the power cost impacts of PSE’s owned resources.[[47]](#footnote-48) The $4.4 million increase estimated by Commission Staff overstates the impact of updating wind forecasts by approximately $2.3 million.

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

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

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

**Table 3. Forecasted and Actual Wind Capacity Factors**

|  |  |  |  |
| --- | --- | --- | --- |
| **Resource** | **StaffProposal** | **HistoricalAverage** | **PSEProposal** |
| Hopkins Ridge | ███% | ███% | ███% |
| Wild Horse | ███% | ███% | ███% |
| Wild Horse Expansion | ███% | ███% | ███% |
| Lower Snake River | ███% | ███% | ███% |
| Klondike III | ███% | ███% | ███% |

As previously discussed, actual wind data for the projects have been consistently below the preconstruction and 2010 DNV wind forecasts. It was reasonable for PSE to obtain new forecasts from an outside expert. The 2016 wind forecasts utilize historical data and current technologies for forecasting wind generation, which are an improvement over the lack of data and technology available for preconstruction wind forecasts. The 2016 wind forecasts provide the best current estimate of energy production from the plants and are more representative of actual results than prior forecasts.

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

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

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

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

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

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

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

**Q. Does PSE agree with Commission Staff’s recommendation that PSE update the day-ahead analysis to include 2016 data?[[48]](#footnote-49)**

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

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

A. Day-ahead wind integration costs changed from $██████ to $██████, a decrease of $████.

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

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

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

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

A. Although no party raised issues with respect to the calculation performed by PSE, Commission Staff opposed the timing of this analysis. Commission Staff recommends against inclusion of a contingent calculation of power costs to account for Microsoft’s partial change to retail wheeling in this proceeding. Instead, Commission Staff expresses a preference for an update if and when Microsoft takes generation from a source other than PSE. The reasons for this preference include concerns that (i) gas and power prices will change (and the calculation should be made with then-existing prices at the time that Microsoft becomes a retail wheeling customer for the majority of its load) and (ii) any modifications to PSE’s power costs in this proceeding ordered by the Commission should also be reflected in the contingent calculation.[[49]](#footnote-50)

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

A. No. PSE does not agree that the contingent calculation should be developed when Microsoft changes to retail wheeling for the majority of its load, based on gas prices other than those used in this proceeding. Power costs projections are based on a set of input assumptions that are inter-related and cannot easily be separated. These include resources, contracts, rate year load, and forward gas prices. Attempts to update power costs by modifying only one or two of these assumptions after a rate period has begun generate inconsistency. A partial update opens up questions of what should and should not be changed. For example:

* Would prices be a combination of actuals for part of the rate year and forwards for the remainder of the rate year, or forwards for a different rate year?
* If prices from a different rate year were used, should load, contracts and resources all be changed to reflect the new rate year?
* Since resources and contracts for a revised rate year would be different from those approved in this proceeding, should those changes be allowed without the opportunity for review by the parties in this proceeding and the Commission?
* If the rate year is not changed but is underway, should actual costs be used in place of projected costs for a portion of the rate year?

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

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

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

The previously authorized Centralia compliance filing to be made by PSE on or before October 1, 2016, will include a limited update to variable power costs with updated rates in Schedule 95 and the updated PCA baseline rate to go into effect on December 1, 2016.[[50]](#footnote-51)

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

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

A. Yes. The intent of the contingent calculation is that it be consistent with the final costs approved in this proceeding. The Ninth Exhibit to the Prefiled Rebuttal Testimony of Paul K. Wetherbee, Exh. PKW-24C, provides projected power costs presented in this rebuttal testimony with the Microsoft special contract qualifying load removed. PSE proposes to update this calculation again with the compliance filing in this proceeding.

**VIII. UPDATED POWER COSTS**

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

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

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

A. PSE updated the AURORA model database for:

(i) three-month average forward gas prices at June 23, 2017 and the short-term rate year power hedges as of the same date;

(ii) an update to the Colstrip fuel and variable dispatch costs based on updated Colstrip budgets;

(iii) an update to reflect the final power purchase agreement with Public Utility District No. 1 of Douglas County, Washington (“Douglas PUD”) for output from the Wells Hydroelectric Project effective September 1, 2018. Projected rate year power costs reflect an increase in PSE’s allocation from 32.07 percent in the initial filing to an average of 32.47 percent in the last four months of the 2018 rate year;

(iv) an update to include energy and costs from one new Schedule 91 contract that started providing energy to PSE in April 2017;

(v) an update to the run setup to remove modeling logic related to compliance with the Clean Air Rule; and

(vi) an update to the model run setup to remove the option selection of “Use Operating Reserves.”

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

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

(i) an update to forecasted fixed gas transport costs to reflect the updated rates charged to PSE for upstream pipeline costs by Northwest Pipeline, Westcoast, and Nova and to correct nonmaterial errors in the original filing;

(ii) the mark-to-market calculation for gas for power contracts in place at June 23, 2017, which also included updating the basis differential forecast for the rate year;

(iii) an update to the rate year Colstrip fixed costs to reflect updated Colstrip budgets;

(iv) an update to reflect fixed and variable costs from the final power purchase agreement with Douglas PUD for output from the Wells Hydroelectric Project effective September 1, 2018 and to correct a fixed costs calculation error in the original filing;

(v) updated rate year budget information for PSE’s Mid-Columbia (“Mid-C”) contracts with Douglas PUD for the output from the Wells Hydroelectric Project, with Public Utility District No. 1 of Chelan County, Washington for the output from the Rocky Reach and Rock Island Hydroelectric Projects and with Public Utility District No. 2 of Grant County, Washington for output from the Wanapum and the Priest Rapids Hydroelectric Projects;

(vi) an update to reflect an updated approach to estimating the impacts of the Clean Air Rule on rate year power costs; and

(vii) other Costs Not in AURORA changes to reflect the updated AURORA dispatch and lower forecast market prices.

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

A. No. PSE continued to use the projected BPA transmission rates that were used in the initial filing. On July 26, 2017, BPA released the Administrator’s Final Record of Decision,[[51]](#footnote-52) which establishes new BPA rates effective October 1, 2017. PSE had completed its power costs analysis for this rebuttal filing prior to BPA’s release of the Administrator’s Final Record of Decision. PSE will update the BPA transmission rates in its power costs projections in the compliance filing in this proceeding. PSE estimates the new BPA transmission rates will result in approximately a $500,000 reduction to power costs.

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

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

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

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

Average rate year gas prices declined from $2.55/MMBtu in the supplemental filing to $2.48/MMBtu in this rebuttal filing. PSE removed the emissions limits on its combined cycle resources in favor of making an adjustment to power costs outside of AURORA. Together, these changes resulted in reductions to the AURORA-generated market power prices. In combination, all of these changes resulted in increased utilization of the combined cycle resources, reduced market purchases, and reduced power costs.

Other factors that contributed to the reduction are updates to upstream pipeline transportation rates, Colstrip and Mid-C hydro budgets, and rate year hedges. 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 |
|  | **Rebuttal power costs** | **$714,857** |

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

A. The power costs declined from $714.9 million in the supplemental filing to $███ million in this rebuttal filing.

**IX. CONCLUSION**

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

A. Yes.

**Redacted
Version**

1. *See* *generally* Wetherbee, Exh. PKW-1CT at 47:4 – 49:8. [↑](#footnote-ref-2)
2. Frankiewich, Exh. KAF-1T at 22:1 – 24:10. [↑](#footnote-ref-3)
3. Frankiewich, Exh. KAF-1T at 25:3-12. [↑](#footnote-ref-4)
4. Frankiewich, Exh. KAF-1T at 25:16 – 26:16. [↑](#footnote-ref-5)
5. Frankiewich, Exh. KAF-1T at 27:3-14. [↑](#footnote-ref-6)
6. Frankiewich, Exh. KAF-1T at 27:18 – 30:3. [↑](#footnote-ref-7)
7. WAC 173-442-050(3)(a). [↑](#footnote-ref-8)
8. WAC 173-442-050(3)(b). [↑](#footnote-ref-9)
9. Frankiewich, Exh. KAF-1T at 24:4-5. [↑](#footnote-ref-10)
10. Frankiewich, Exh. KAF-1T at 24:Table 2. [↑](#footnote-ref-11)
11. WAC 173-442-160(5)(b)(i). [↑](#footnote-ref-12)
12. Final Cost-Benefit and Least-Burdensome Alternative Analysis, September 2016, Publication no. 16-02-015, pages 16-18. [↑](#footnote-ref-13)
13. Frankiewich, Exh. KAF-1T at 7:12 – 13:11. [↑](#footnote-ref-14)
14. Frankiewich, Exh. KAF-1T at 13:15 – 17:9. [↑](#footnote-ref-15)
15. *Wash. Utils. & Transp. Comm’n v. Pac. Power & Light Co.*, Docket UE-152253, Order 12 at ¶¶ 223-24 (Sept. 1, 2016). [↑](#footnote-ref-16)
16. Frankiewich, Exh. KAF-1T at 14:1-3. [↑](#footnote-ref-17)
17. *Wash. Utils. & Transp. Comm’n v. Puget Sound Energy, Inc.*, Dockets UE-111048 & UG-111049, Order 08 at ¶ 251 (May 7, 2012). [↑](#footnote-ref-18)
18. Wetherbee, Exh. PKW-1CT at 62:5-8. [↑](#footnote-ref-19)
19. Wetherbee, Exh. PKW-1CT at 63:Table 16. [↑](#footnote-ref-20)
20. Wetherbee, Exh. PKW-1CT at 63:3 – 64:2. [↑](#footnote-ref-21)
21. Gomez, Exh. DCG-1CT at 18:1-15. [↑](#footnote-ref-22)
22. Gomez, Exh. DCG-1CT at 18:15-18. [↑](#footnote-ref-23)
23. Gomez, Exh. DCG-1CT at 19:8-10. [↑](#footnote-ref-24)
24. Gomez, Exh. DCG-1CT at 18:5-10. [↑](#footnote-ref-25)
25. Wetherbee, Exh. PKW-1CT at 63:Table 16. [↑](#footnote-ref-26)
26. Gomez, Exh. DCG-1CT at 17, n.35. [↑](#footnote-ref-27)
27. Gomez, Exh. DCG-1CT at 22:3 – 23:3. [↑](#footnote-ref-28)
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). [↑](#footnote-ref-29)
29. Gomez, Exh. DCG-1CT at 22:20 – 23:3. [↑](#footnote-ref-30)
30. *See* Gomez, Exh. DCG-1CT, at page 24, lines 3-7. [↑](#footnote-ref-31)
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>. [↑](#footnote-ref-32)
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. [↑](#footnote-ref-33)
33. Gomez, Exh. DCG-1CT at 26:6-12. [↑](#footnote-ref-34)
34. Gomez, Exh. DCG-1CT at 31:4-13. [↑](#footnote-ref-35)
35. Gomez, Exh. DCG-1CT at 31:16-18. [↑](#footnote-ref-36)
36. Gomez, Exh. DCG-1CT at 32:1-3. [↑](#footnote-ref-37)
37. Gomez, Exh. DCG-1CT at 32:5-7. [↑](#footnote-ref-38)
38. Gomez, Exh. DCG-1CT at 31:4-13. [↑](#footnote-ref-39)
39. Gomez, Exh. DCG-1CT at 31:16-18; *id*. at 31:fn. 57; *see* Mullally, Exh. MM-11 at 22-23. [↑](#footnote-ref-40)
40. Gomez, Exh. DCG-1CT at 31:fn. 57. [↑](#footnote-ref-41)
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.” [↑](#footnote-ref-42)
42. Wetherbee, Exh. PKW-20C at 66. [↑](#footnote-ref-43)
43. Gomez, Exh. DCG-1CT at 27:fn. 51. [↑](#footnote-ref-44)
44. Gomez, Exh. DCG-1CT at 28:1-12. [↑](#footnote-ref-45)
45. Gomez, Exh. DCG-1CT at 27:fn. 51. [↑](#footnote-ref-46)
46. North American Electric Reliability Corporation, *Generating Availability Data System Reporting Instructions*, available at <http://www.nerc.com/files/Section_3_Event_Reporting.pdf>. [↑](#footnote-ref-47)
47. Gomez, Exh. DCG-1CT at 25:5-10. [↑](#footnote-ref-48)
48. Gomez, Exh. DCG-1CT at 14:13 – 15:4. [↑](#footnote-ref-49)
49. Gomez, Exh. DCG-1CT at 33:19 – 35:10. [↑](#footnote-ref-50)
50. *Wash. Utils. & Transp. Comm’n v. Puget Sound Energy*, Dockets UE-121697, et al., Joint Petition to Modify Order 07 ¶ 8. [↑](#footnote-ref-51)
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>. [↑](#footnote-ref-52)