Exh. DCG-1CT
Dockets UE-170033/UG-170034
Witness: David C. Gomez
CONFIDENTIAL VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-170033 and UG-170034 (*Consolidated*)**

TESTIMONY OF

David C. Gomez

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Pro Forma Power Costs, Rate Year Operations and Maintenance Expense, and Wells Hydroelectric Project Power Purchase Agreement

June 30, 2017

CONFIDENTIAL PER PROTECTIVE ORDER

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David C. Gomez. My business address is the Richard Hemstad Building, 1300 S. Evergreen Park Drive S.W., Olympia, Washington 98504.

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

A. I am employed by the Washington Utilities and Transportation Commission ("Commission") as the Assistant Power Supply Manager in the Energy Section of the Regulatory Services Division. I attained this position on July 1, 2012. Prior to my current position, I was the Deputy Assistant Director in the Solid Waste and Water Section of the Regulatory Services Division.

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

A. I have been employed by the Commission since May 2007.

Q. Please state your educational and professional background.

A. I hold a Bachelor of Arts degree in Business from Hamline University and a Masters of Business Administration degree from the University of Saint Thomas; both universities are located in Saint Paul, Minnesota.

Before joining the Commission, my relevant professional experience consisted of 25 years in a variety of fields, including management, contracting, supply chain, procurement, operations and engineering. I hold professional certifications from the Institute for Supply Management (ISM); APICS – The Association for Operations Management; Universal Public Procurement Council (UPPC); and QAI Global Institute (Software Testing).

Q. What are your duties with the Commission?

A. I perform accounting and financial analysis of regulated utility companies, as well as legislative and policy analysis. I presented testimony on behalf of Commission Staff in Docket UE-121373, regarding the Coal Transition Power Purchase Agreement between Puget Sound Energy and TransAlta Centralia Generation LLC; Dockets UE-130043 and UE-140762, PacifiCorp's 2013 and 2014 general rate cases; Docket UE-130617, Puget Sound Energy's 2013, 2014 and 2016 Power Cost Only Rate Cases (PCORCs); and Dockets UE-140188, UE-150204 and UE-160228, Avista's last three general rate cases. I have provided Staff recommendations to the Commission at numerous open meetings, and worked on various Commission rulemakings.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the scope of your testimony in this proceeding?

A. My testimony addresses the Company's projected rate year power costs contained in the prefiled direct and supplemental testimony of Puget Sound Energy's (PSE or Company) witnesses Mr. Paul Wetherbee, Mr. Ronald Roberts and Mr. Michael

Mullally. Some of the issues contained within the testimony of the Company witnesses listed above are addressed by other members of Commission Staff.[1]

In Mr. Mullally's testimony, I evaluate PSE's renewal of the Wells Hydroelectric Project Power Purchase Agreement (Wells PPA). In Mr. Robert's testimony, I respond to the Company's presentation of its rate year Production Operations and Maintenance expense. Finally, in Mr. Wetherbee's testimony, I cover all of the issues presented in his testimony except:

- Costs and benefits associated with PSE's participation in the California Independent System Operator (CAISO) Energy Imbalance Market (EIM);
- Estimated rate year power costs associated with compliance to Washington's Clean Air Rule (CAR); and
- Disposition of PSE's surplus property from its discontinued operations associated with the White River Hydroelectric Project.

Q. What issues are you addressing in your testimony?

A. The first part of my testimony covers the costs and prudency of PSE's new and renewed contracts for transmission of electricity and renewal of the Well's PPA. The second part of my testimony focuses on my adjustments to the pro forma power costs proposed by the Company in Mr. Robert's testimony; Production Operations

[1] Staff's response to Mr. Mullally's prefiled direct testimony regarding PSE's acquisition of the City of Buckley gas system and the Glacier Battery Storage System Pilot are contained in the testimony of Mr. Cooper Wright and Ms. Jennifer Snyder respectively. PSE's closure plans for Colstrip 1&2 are addressed by Mr. Christopher Hancock in his testimony. Staff witness Mr. Kyle Frankiewich responds to the Company's testimony regarding EIM cost-benefit and CAR compliance and finally, Mr. Cooper Wright provides Staff's response on the disposition of surplus property from the White River Hydroelectric Project.

and Maintenance Expense, as well as adjustments to Mr. Wetherbee's rate year power costs presented in his testimony.

Q. Can you summarize the amount of your adjustments to power cost expense for the rate year?

A. Yes. PSE proposes $737.7 million in rate year power costs per its supplemental filing of April 3, 2017. I reduce this by $11.1 million. Most of my adjustment to pro forma power costs ($6.1 million) relates to PSE's revisions to the Aurora power cost model for dispatch of its gas-fired resources. I contest the capacity factor derates for its wind generation resources ($4.4 million). I also reduce the Production Operations and Maintenance Expenses for hydro licensing activities in the rate year at the Company's Baker and Snoqualmie Hydroelectric projects ($0.6 million).

In addition to the adjustment above, I also recommend that PSE update on compliance (prior to final rates going into effect) the estimate of its rate year Day-Ahead costs used to calculate the Company's wind integration costs.[2]

III. TRANSMISSION CONTRACT RENEWALS AND ADDITIONS

Q. Can you summarize the transmission contract renewals and additions which PSE has presented in this case?

[2] This final update to power costs should also include re-run of the AURORA model to reflect the most recent gas price forecasts for the rate year.

A. Yes. There are a total of 12 Bonneville Power Administration (BPA) transmission contracts. The Company requests a prudency determination from the Commission on all of them.[3]

In his prefiled direct testimony, Mr. Paul Wetherbee quantifies the impact on rate year power costs of the nine renewed transmission contracts at $13.8 million.[4] The Company uses six of these nine renewed contracts[5] to access the Mid-Columbia (Mid-C) trading hub to make short-term market purchases. The remaining three of the nine renewed contracts are earmarked for Mint Farm (two contracts totaling 20 MW) and the Centralia coal plant (100 MW).[6]

In addition to these nine BPA transmission contracts, PSE included three new BPA contracts that allow for generation capacity increases to both the Mint Farm and Goldendale Generation Stations.[7] These three new contracts total 53 MW and contribute $1.2 million to rate year power costs.[8]

Q. What standard did you rely on to evaluate the prudency of the Company's BPA transmission contract renewals and additions described above?

A. I relied on the Commission's standard below which Staff has consistently applied in other cases:

> The Commission has consistently applied a reasonableness standard when reviewing the prudence of decisions relating to

[3] Wetherbee, Exh. PKW-1CT at 16:1, Table 4.
[4] Wetherbee, Exh. PKW-1CT at 30:1-4, Table 9.
[5] Two Vantage contracts totaling 123 MW; Two Rocky Reach contracts totaling 200 MW; Midway @ 100 MW; and Montana Purchases/Garrison @ 94 MW.
[6] Wetherbee, Exh. PKW-1CT at 14:14 - 16:1.
[7] In its calculation of rate year power costs in this proceeding, PSE has included the benefit of increased generating capacity from both Mint Farm and Goldendale (*see* Wetherbee, Exh. PKW-1CT at 59:17-24).
[8] Wetherbee, Exh. PKW-1CT at 34:18-19, Table 11.

> power costs, including those arising from power generation asset acquisitions. The test the Commission applies to measure prudence is what a reasonable board of directors and company management would have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. The company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made.[9]

To determine prudency, the Commission focuses on four factors in applying this standard: (1) Resource need; (2) Evaluation of alternatives; (3) Communication with and involvement of the company's board of directors; and, (4) Adequate documentation.

Q. Has the Company adequately demonstrated a need for the BPA transmission contracts it proposes to include in rates?

A. Yes. Referring to PSE's 2015 Integrated Resource Plan (IRP), transmission capacity to the Mid-C market hub gives the Company access to the principal electricity market hub in the Northwest and one of the major trading hubs in the Western Electricity Coordinating Council (WECC). It is also the central market for northwest hydroelectric generation.[10] The Company's IRP lists a total of 1,975 MW of contracted BPA transmission capacity of which 1,666 MW provides PSE with a significant portion of its winter peak needs. As mentioned previously, six of PSE's

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[9] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12, at 8:19 (April 7, 2004).

[10] Gomez, Exh. DCG-2, PSE's 2015 Integrated Resource Plan, Appendix D, Electric Resources, p. D-17.

nine renewed BPA transmission contracts are used by the Company to access short-term market purchases and represent 517 MW[11] or about one-quarter of this total transmission capacity. As stated by Mr. Wetherbee in his testimony, these six renewed BPA transmission contracts "are an integral part of PSE's electric resource portfolio and are necessary to provide capacity and energy."[12]

The remaining three renewed contracts and all three of the new contracts are required to deliver generated power to and from resources already in-service and which have been already been deemed prudent in previous Commission Orders.[13]

Q. Has the Company adequately demonstrated that it evaluated alternatives to the BPA transmission contracts it proposes to include in rates?

A. Yes. Mr. Wetherbee's testimony presents the results of the Company's analysis of the alternatives considered using its Portfolio Screening Model (PSM III). The results of this analysis determined that the six BPA transmission contracts used to access short term market purchases result in $284.3 million in portfolio benefit over the 20 year planning horizon used by PSM III.[14]

As stated before in my testimony, the remaining BPA transmission contracts entered into by PSE are required to wheel power to and from resources presently

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[11] Two Vantage contracts totaling 123 MW; Two Rocky Reach contracts totaling 200 MW; Midway @ 100 MW; and Montana Purchases/Garrison @ 94 MW.
[12] Wetherbee, Exh. PKW-1CT at 15:1-4.
[13] Mint Farm, *see Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-090704, Order 11, ¶ 337 (April 2, 2010); Goldendale, *see Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-070565, Order 07, ¶ 21 (August 2, 2007); Coal Transition Power Purchase Agreement, *see Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-121373, Order 03, ¶ 119 (January 9, 2013).
[14] Wetherbee, Exh. PKW-1CT at 20:19-20 (Table 5), 23:17-18 (Table 6) and 28:1-3 (Table 8).

serving customers as well as to realize the full benefits associated with capacity and heat rate improvements to both Mint Farm and Goldendale.[15] As such, Staff does not see a need for the Commission to make a separate prudency determination for these contracts.

Q. Was the Company's Board of Directors informed and involved in the decision regarding these BPA transmission contract renewals and additions?

A. Yes. PSE management presented to the Energy Management Committee (EMC) on numerous occasions with the exception of those contracts serving Mint Farm and Goldendale generating stations and the Coal Transition Power Purchase Agreement.[16]

Q. Did the Company provide adequate documentation to support a prudency finding by the Commission for the six renewed BPA transmission contracts it uses to access short term market purchases?

A. Yes. PSE has provided both testimony and workpapers, which Staff has examined and believes support a prudency finding for these six renewed BPA transmission contracts.

[15] Staff witness Mr. Cooper Wright addresses in his testimony the prudency of the capacity upgrades to both Mint Farm and Goldendale.

[16] Wetherbee, Exh. PKW-1CT at 28:12-17. According to Mr. Wetherbee, PSE policy does not require Energy Management Committee approval of a transmission contract supporting an underlying resource where the contract term is within the operating life of that resource.

Q. Applying the Commission's prudency standard and factors described above, what is your recommendation concerning the Company's BPA transmission contracts?

A. I recommend that the Commission find the Company's six BPA transmission contract renewals used to access short term market purchases along with their corresponding costs to be prudently incurred and support their inclusion in rate year power costs. As for the remaining BPA transmission contracts, Staff supports their inclusion in rate year power costs.

IV. WELLS HYDROELECTRIC POWER PURCHASE AGREEMENT

Q. Does Staff support the Company's proposal to include $13.0 million in costs associated with its renewed power purchase agreement with Douglas County Public Utility District (PUD) for a portion of the output from the Wells Hydroelectric Project (Wells) in the 2018 rate year?

A. Yes. Company witness Mr. Mullally provides a thorough explanation of PSE's analysis and ultimate decision to enter into a 10-year power purchase agreement (PPA) with Douglas County PUD. Depending on PSE's contractual output share from Wells, the Company has estimated between $15 and $40 million in net present value benefit.[17]

[17] Mullally, Exh. MM-1HCT at 24:1-5.

Q. What other benefits does the Wells PPA convey to ratepayers?

A. It avoids the sudden loss of over 200 MW of an existing carbon-free resource currently serving customers.[18] It also provides PSE with operational flexibility in responding to changes in loads and outputs within its Balancing Authority. PSE also evaluated the Wells PPA against full and partial resource builds, varying natural gas market price scenarios and actual resource proposals received from independent power producers. In each case, the Company found that the Wells PPA conveyed the greatest amount of portfolio benefits over the other alternatives considered.

V. RATE YEAR PRODUCTION OPERATIONS & MAINTENANCE EXPENSE

Q. What is the amount of rate year production Operations and Maintenance (O&M) expense that PSE is seeking to recover in this case?

A. The Company's total O&M costs for the rate year are $147.0 million, an increase of $13.9 million as compared to the 2014 PCORC production O&M costs of $133.1 million.[19] For the most part, PSE applies methodologies to determine rate year O&M expenses agreed to by parties in previous settlements approved by the Commission. For example, the Company uses a "defer and amortize" approach to calculate major maintenance rate year expenses for its thermal fleet (coal and gas

[18] Mullally, Exh. MM-1HCT at 28:3-11. According to PSE, if it did not renew the Wells PPA, it would experience an over 150 MW capacity deficit to meet its winter peak needs in 2018.
[19] Roberts, Exh. RJR-1CT at 56:15-19.

generating stations).[20] As a result, the Company's presentation of O&M costs for the rate year is largely uncontroversial. However, Staff does recommend an adjustment downward to the hydro licensing O&M costs PSE is projecting for the rate year.

Q. What is the impact to rate year power costs associated with Staff's recommended adjustment of PSE's hydro licensing O&M?

A. Staff proposes to reduce PSE's rate year costs for its licensing activities relating to Snoqualmie and Baker Hydroelectric projects to reflect test year levels. The effect of this adjustment reduces rate year O&M expense by $0.6 million.

Q. Why do you believe the adjustment to PSE's rate year hydro licensing activities is appropriate in this case?

A. The Company's confidential response to UTC Staff Data Request No. 175 provides the 2012 through 2016 year-to-year variances (budget to actual) by Work Breakdown Structure (WBS)[21] for licensing activities for both the Baker and Snoqualmie projects. Staff examined the variances, both within individual WBS and the totals for each of the two projects, and concluded that the rate year budgeted amounts are

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[20] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-130617, Order 06 (October 23, 2013), Appendix A - Settlement Stipulation, ¶ 17; and *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-141141, Order 04 (November 3, 2014), Appendix A – Settlement Stipulation, ¶ 11.

[21] "Work Breakdown Structure" or "WBS," is a term used in project management and systems engineering whereby a project is broken down into smaller components that organizes the team's work into manageable sections for detailed cost estimating and control along with providing guidance for schedule development and control.

not sufficiently known and measurable to the standard established by the Commission for pro forma adjustments to test year results.[22]

While the Commission's known and measurable standard allows for considerable discretion in its application, the history of significant swings in budget versus actual amounts in these two activities clearly supports the use of only test year amounts for Snoqualmie and Baker Hydroelectric project's licensing activities planned in the rate year.

Q. For the years 2012 through 2016, what level of variability did you observe between budgeted and actual expenditures associated with licensing activities for Snoqualmie and Baker Hydroelectric projects?

A. In almost all instances examined between 2012 and 2016, actual expenditures were significantly less than budgeted expenditures.[23] For Snoqualmie, budget level accuracy averaged slightly under 70 percent of the amount it had originally budgeted for that year. Within WBS categories, Staff observed even greater variability: the range of WBS budget to actual variance amounts was between -447 and 463 percent for both projects. For Baker, only in 2016 did budget amounts equal actual expenditures. For the remaining years, Baker's actual annual expenditures on licensing activities averaged 93 percent of the amount it had originally budgeted for that year.

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[22] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-130043, Order 05, ¶ 198 (Dec. 4, 2013).

[23] Gomez, Exh. DCG-3C, PSE's confidential Response to Staff Data Request No. 175, Attachments A & B.

Q. Did the Company provide any explanation for the cause of these variances to budget?

A. Yes. In its response to UTC Staff Data Request No. 175, PSE indicates that hydro licensing budgets for Baker and Snoqualmie were often underrun as capital expenses displaced budgeted licensing activities. The Company also admits to overestimations of budget as another reason.[24] The explanations offered by the Company in its response only serve to confirm that PSE's proposed pro forma adjustments to its test year O&M hydro licensing costs are not known and measurable for the purpose of setting rates. For this reason, Staff recommends using the Company's test year amount of $2.9 million for both Baker and Snoqualmie Licensing O&M for the rate year. As I mentioned before, the effect of my proposed adjustment reduces rate year power costs by $0.6 million.

VI. RATE YEAR PRO FORMA POWER COSTS

A. Day-Ahead Wind Integration Costs

Q. What is the total amount of costs PSE has included in the rate year for Wind Integration?

A. The Company has included a total of $11.1 million in rate-year wind integration costs for Hopkins Ridge, Lower Snake River (LSR), Wild Horse, Wild Horse

[24] *Id.*, PSE's explanatory notes in worksheet tab titled "OM Detail."

Expansion and Klondike III. The majority ($7.7 million) of this total is captured in PSE's rate year transmission costs and is based on rates published in BPA's Open Access Transmission Tariff (OATT). The remaining $3.4 million is comprised of Hour-Ahead wind integration costs for both Wild Horse and Wild Horse Expansion and $1.0 million in Day-Ahead wind integration costs for all of its wind generation resources. My testimony below focuses on PSE's presentation of its pro forma Day-Ahead wind integration costs, which attempts to quantify the dollar impact of the variation between wind resource Day-Ahead forecasts and actual hourly production in the rate year.

Q. Is an adjustment to rate year costs appropriate given your examination of wind integration costs?

A. Yes. PSE relied on historical data through 2015 to calculate its $1.0 million in rate year Day-Ahead costs for its wind generation resources.[25] The Company did not include 2016 data as it was not available to coincide with the timing of the Company's initial filing of this case. The use of the most recent historical data of the variation between wind resource Day-Ahead forecasts and actual hourly production for the purposes of establishing the power cost baseline for the rate year is in keeping with the Commission's determination on the treatment of wind integration costs in PSE's 2011 general rate case.[26] As a result, I recommend the Commission's final order direct PSE to update rate year Day-Ahead costs to include data from 2016 at

[25] Klondike III, 2008-2015; Hopkins Ridge, 2007-2015; Wild Horse, 2007-2015; and LSR, July 2012-2015.
[26] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc*., Dockets UE-111048, et al., Order 08 ¶¶ 249-253 (May 7, 2012).

the same time all other power costs are updated prior to rates going into effect. Staff does not know whether this would result in an increase or decrease to rate year expense, but supports this update as consistent with the Commission's historical treatment of such costs.

B. AURORA Model Dispatch of Gas-Fired Resources

Q. Please describe PSE's proposed change to how it models the hourly dispatch of its gas-fired generation resources in AURORA.

A. In his prefiled direct testimony, Mr. Wetherbee states: "In the 2014 PCORC only variable operating costs were used to model dispatch of the gas-fired resources in Aurora. This was consistent with the actual operational decisions at the time."[27] He goes on to say that, "PSE re-examined its costs in an effort to better understand its costs and more closely align the information used for operational dispatch decisions with the true costs of operating its generation units. In this review process, PSE updated its estimates for variable O&M and major maintenance."[28]

The principal change in PSE's AURORA input values is the inclusion of maintenance expenses (both corrective and major) which affect the model's dispatch of its gas fired plants and, according to the Company's confidential response to UTC Staff Data Request No. 177, increases rate year power costs by $6.1 million.[29]

[27] Wetherbee, Exh. PKW-1CT, page 60:9-11.
[28] Wetherbee, Exh. PKW-1CT, page 60:12-15.
[29] Gomez, Exh. DCG-4C, PSE's confidential Response to UTC Staff Data Request No. 177, Part G.

Q. Is Staff in support of these AURORA Model changes?

A. No.

1. AURORA Variable Operations & Maintenance (VOM) Input Values

Q. How did the Company calculate its VOM input values for use in the AURORA model in this case?

A. In his direct testimony, Mr. Wetherbee states that PSE developed its VOM input values in AURORA using "industry definitions" and "three years of historical data" for the Company's assets.[30] In his response to UTC Staff Data Request No. 177, Mr. Wetherbee provides the actual analysis[31] along with the industry definitions,[32] which the Company said it relied on to arrive at these values for input into AURORA.[33] In his response to UTC Staff Data Request No. 177, Mr. Wetherbee also describes the differences in how PSE calculated VOM input values for the 2014 PCORC, Docket UE-141141, versus how the Company calculated the VOM input values in this case.[34]

In the 2014 PCORC, PSE's VOM input values in AURORA were based on: the costs associated with demineralization chemicals, heat recovery steam generator

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[30] Wetherbee, Exh. PKW-1CT at 60:6-18.

[31] Gomez, Exh. DCG-12C, PSE's confidential Response to UTC Staff Data Request No. 177, Attachment A.

[32] Gomez, Exh. DCG-5, PSE's Response to UTC Staff Data Request No. 177, Attachment G, CAISO's "Final Methodology for Calculating Variable Operation and Maintenance Cost under the Variable Cost Option" (Ronald R. McNamara, October 6, 2011, V1.1).

[33] The results of this analysis are summarized in Mr. Wetherbee's direct testimony, Exh. PKW-1CT at 63:1 (Table 16).

[34] Gomez, Exh. DCG-4C, PSE's confidential Response to UTC Staff Data Request No. 177, Parts C-F.

chemicals, emissions chemicals, cooling tower chemicals and station power and water. In this case, the Company's VOM input values in AURORA include these items, but now also add the cost of consumables and corrective maintenance. For the Company's Combined Cycle plants, the VOM input value also includes a major maintenance adder expressed in dollars per MWh.

Examining the Company's workpapers provided in its response to UTC Staff Data Request No. 177, PSE's VOM input values in this case were calculated using historical O&M costs from 2013-2015 along with the corresponding actual net generation for each of its gas-fired resources over that same period.[35] PSE then divided the O&M cost total by the net generation total to calculate a dollar per MWh VOM input value for each gas plant. PSE then compared these calculated VOM input values, based on actual costs from a period that pre-dates the test year, with Default O&M Cost Adders specified by CAISO[36] and selected the higher of the two as its VOM input value in AURORA for all but two gas plants (Encogen and Fredrickson 1).

Q. Do PSE's calculated VOM input values or CAISO's Default O&M Cost Adders have any relation to PSE's projection of rate year O&M costs presented by the Company in this case?

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[35] Gomez, Exh. DCG-12C. There appears to be a mathematical error in how PSE calculated its net generation amounts for Encogen in its workpapers (*see* workpaper tab titled; ENC_VOM, Cell B456). For Encogen, the Company included in its total, net and gross MWh generation amounts. This overstates the plant's generation over the 2013-2015 period.

[36] Gomez, Exh. DCG-6, PSE's Response to UTC Staff Data Request No. 177, Attachment C, CAISO Business Practice Manual for Market Instruments, Version 44 (April 6, 2017), Section 4.1 – Daily & Hourly Bid Components, Exhibit 4-2, p. 41.

A. None whatsoever. PSE's projected $147.0 million in rate year O&M expense (including deferred and amortized major maintenance amounts) accounts for these costs as an out-of-model adjustment and is reflected in the Company's rate year revenue requirement. Mr. Robert's O&M amounts are based on test year actuals with known and measurable pro forma adjustments. Earlier in my testimony, I comment on the Company's presentation of production O&M expenses for the rate year as being largely uncontroversial.[37] This statement reflects PSE's application of previous settlements and Commission orders which directly addressed the issue of O&M cost treatment and recovery driven largely by the increase in starts and run times of the Company's thermal generation assets.[38]

In contrast, CAISO's Default O&M Cost Adders were developed using O&M cost data across different generation technologies in order to arrive at "approximate values of variable O&M costs for <u>California generating stations</u>."[39] CAISO also relied on decade-old cost assumptions from the Energy Information Administration (EIA). PSE's calculated VOM input values, which it compared to CAISO's Default O&M Cost Adders, are also based on outdated plant costs and generation data from 2013-2015 predating the test year used in this case and thus, are not accurate depictions of test year O&M cost levels.

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[37] *Supra* Section V.
[38] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc*., Dockets UE-111048, et al., Order 08 ¶ 217 (May 7, 2012); and *WUTC v. Puget Sound Energy, Inc.*, Docket UE-130617, Order 06, ¶ 57 (October 23, 2013).
[39] Gomez, Exh. DCG-5, Section 4 - Description of the Methodology Used to Develop the Current Values for the Variable Operations and Maintenance Cost Adder, p. 3 (emphasis added by Staff).

Q. If PSE's proposed VOM input values are not representative of PSE's O&M costs of its gas fired resources, which VOM input values would Staff support for use in the AURORA model?

A. While recognizing that some level of variable O&M costs should be included in the AURORA model, Staff finds PSE's analysis and estimates inadequate for this purpose. Certainly, CAISO's Default O&M Cost Adders should not be used at all for reasons I already mentioned.

Staff would be more inclined to support VOM input values in AURORA that are based on the same test year data and loads relied upon by PSE to determine its rate year O&M production expense outside the model. In Attachment F to the Company's response to UTC Staff Data Request No. 177, PSE provides VOM input values using the same approach it employed in the 2014 PCORC. These values also suffer from the same malady as PSE's calculated VOM input values; they were arrived at using the same outdated cost data.

Q. You mentioned earlier that PSE expanded the category of O&M costs it includes in the calculation of its VOM input values. Do you agree that these items should be included?

A. Yes. While the inclusion of consumables and corrective maintenance costs in calculating VOM input values may be appropriate, Staff lacks the time and resources to extract the necessary information from the Company through additional discovery in order to offer the Commission an alternative VOM input value based on test year O&M expense levels. For example, Mr. Robert's workpapers include almost 17,000 individual maintenance expense line items from the test year. These many thousands of expense line items in Mr. Robert's workpapers would have to be filtered to include only expense line items that indeed conform to the generally accepted definition of variable costs which, in the case of PSE gas-fired generation resources, are a function of how much they operate. Even with good data this can be a subjective exercise with no bright line to render it uncontroversial. As it currently stands, the exercise would be impracticable.

Q. With all of the issues you identify regarding PSE's proposed VOM input values, what is your recommendation in this case?

A. Staff recommends the Commission reject the Company's VOM input values and require the Company, on compliance, to recalculate its VOM input values for AURORA using actual test year data for both loads and O&M costs for demineralization chemicals, heat recovery steam generator chemicals, emissions chemicals, cooling tower chemicals, station power and water, consumables and corrective maintenance. The updated VOM input values, if properly presented and supported, can then be included when PSE re-runs AURORA to update its power costs near the conclusion of this case. For PSE's Combined Cycle plants, Staff recommends the Commission reject entirely the inclusion of a major maintenance cost adder (MMA) to the VOM input value.[40]

[40] For simple cycle (peaker plants), the Company calculated an MMA value in AURORA based on the number of starts.

2. Major Maintenance Cost Adders

Q. What are "major maintenance cost adders?"

A. MMA adders are a construct of CAISO's market bidding process.[41] Market participants, like PSE, provide major maintenance data to CAISO for each participating resource. The MMA adder provided by market participants is applied by CAISO in certain bid award situations where a generator has been committed in advance (sometime days), but due to a change in load requirements at the time of delivery, is dispatched in real-time at the generator's minimum output level. MMA adders are thus designed to ensure these generators, upon settlement, recover their fixed costs of production.

Q. Do PSE's calculated MMA adders reflect, in any way, the Company's rate year major maintenance expenses contained in Mr. Robert's testimony?

A. No.

Q. PSE includes MMA cost adders as inputs in AURORA. Is this appropriate?

A. No. PSE asserts that it takes into account major maintenance events in planning the daily dispatch of generation resources.[42] The Company therefore decided in this case to include, as input values in AURORA, MMA adders which the model uses in

[41] Gomez, Exh. DCG-6, PSE's Response to UTC Staff Data Request No. 177, Attachment C, CAISO Business Practice Manual for Market Instruments, Attachment G, Maximum Start-up and Minimum Load Values under the Registered and Proxy Cost Options, Page 239.
[42] Wetherbee, Exh. PKW-1CT at 61:13-15.

conjunction with other parameters in determining the hourly dispatch of its gas fired resources.

In light of how CAISO uses MMA adders, PSE's decision to include them in AURORA for its gas fired resources in the context of determining rate year power costs in this case is inappropriate for several reasons. First, and most importantly, the Company's major maintenance expenses are already accounted for and included as an out of model adjustment in AURORA. Commission acceptance of the Company's proposal would essentially allow double accounting, and recovery, for these expenses. Second, neither Mr. Wetherbee nor the Company offer any analysis or evidence to support the Company's claim that including MMA adders better characterizes unit commitment and dispatch of its gas fired resources in the model. PSE already includes other input parameters for its gas plants in AURORA like heat rates, minimum capacity and run times, as well as the plant's fuel costs. PSE has argued before that these parameter settings inform unit commitment and dispatch in the model for PSE's gas fired generation.[43]

Further support for rejecting PSE's inclusion of major maintenance adders in modeling rate year power costs for its gas-fired resources is lent by the Commission's own words in the attachment to its acknowledgment letter of PSE's 2015 IRP:

> PSE's 2015 IRP also changes the way that major maintenance at peaking plants is modeled. In earlier IRPs, major maintenance was treated as a fixed cost, while in the 2015 IRP major maintenance is included in the plant's variable costs. This change was not described in the IRP. As a result of this increase in variable costs,

[43] Gomez, Exh. DCG-14, *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, prefiled rebuttal testimony of David E. Mills, Exh. DEM-11CT, pp. 39:3 - 40:19.

> the 2015 IRP's base case includes no output (zero MWh) from peaking plants over the 20-year planning horizon. The Commission does not believe this result is reasonable.[44]

Q. Did the Company provide evidence in its originally-filed case or its supplemental filing that MMA adders better inform AURORA model results?

A. No. PSE included MMA adders in AURORA without providing any evidence that the inclusion of these fixed costs do not actually distort model results by overstating the marginal cost of production of its gas fired resources. The Company alludes to a "review process" it conducted whereby PSE adopted AURORA input values it claims more closely align the model's results with its actual operational dispatch and the "true costs" of operating its gas-fired generating units. While this might sound credible, Staff can find no evidence that PSE's review applied the analytical rigor required to justify such a change. Such evidence is particularly necessary, here, since the change has a material effect on rates. It is also puzzling to Staff why PSE has chosen to ignore the Commission's recommendations in response to its 2015 IRP by bringing this issue up in the GRC and not in its next IRP. In fact, PSE's principal evidence, its workpapers provided through discovery, are nothing more than a recycling of the Company's CAISO resource input templates and workpapers used two-years ago when it first joined the EIM market. The Company also refers to CAISO Business Practice Manuals as further justification which, upon review, Staff finds inapt to the issue of power cost modeling in this case.

[44] *Puget Sound Energy's 2015 Electric and Natural Gas Integrated Resource Plan*, Dockets UG-141169 and UE-141170, Acknowledgment Letter and Attachment, 8 (May 9, 2016).

Q. Please briefly summarize your recommendation(s) for variable operation and maintenance and major maintenance adders?

A. I recommend the Commission reject the Company's CAISO VOM input values and require the Company, on compliance, to recalculate VOM input values for AURORA using test year loads and O&M costs. In addition, the Commission should also reject the inclusion of MMA adders in modeling power costs in this case. These recommendations result in a reduction in rate year power costs of $6.1 million.

C. Projected Wind Generation

Q. Please explain in general how PSE arrived at capacity factors for its wind resources when these projects first went into service?

A. In its response to UTC Staff Data Request No. 311, PSE provides its initial studies of estimated annual energy production for each of its wind projects currently in service.[45] These initial studies are generally described as an independent assessment of the wind climate and expected energy production of each wind project. The P50 probability statistic derived from these studies was used by PSE to establish each project's initial capacity factor for use in the AURORA model. P50 is the long-term mean level of generation: half of the year's output is expected to surpass this level, and the other half is predicted to fall below it. The results of the initial studies are summarized below:

[45] Gomez, Exh. DCG-11C, PSE's Response to UTC Staff Data Request No. 311, Attachments B-F.

Project	Year in Service	Capacity Factor (P50)	P50 Net Energy Output (GWh/year)
Hopkins Ridge	2005	35.0 percent	457.9
Wild Horse	2006	32.3 percent	646.7
Wild Horse Expansion	2009	23.2 percent	89.3
Lower Snake River (LSR)	2011	29.9 percent	899.0
Klondike III (PPA)	2007	35.6 percent	703.9

Q. Please describe PSE's change to how it modeled the output of its wind resources in AURORA?

A. PSE has derated the capacity factors of its wind resources in the AURORA model. Together, the effect of PSE's derating of wind resource capacity factors in the AURORA model for this case results in: the reduction of 99,000 MWhs of wind energy output;[46] and, the addition of approximately $4.4 million to rate year power costs.[47] In addition, PSE's PPA share of the output from Klondike III for the rate year was reduced by the Company an additional 28,000 MWh based on forecasts from the owner of that facility.[48]

Q. Did PSE provide the rate year dollar impact to power costs caused by reducing the capacity factors of its wind resources in the AURORA model?

A. No. Staff obtained this information through discovery.

[46] Wetherbee, Exh. PKW-1CT at 71:11-13.
[47] Gomez, Exh. DCG-8C, PSE's confidential Response to UTC Staff Data Request No. 259.
[48] Wetherbee, Exh. PKW-1CT at 71:14-18.

Q. What did PSE rely on to arrive at the wind capacity factors it used to model power costs in this case and did the Company provide this document in its initial or supplemental filings??

A. PSE contracted with Vaisala Corporation (Vaisala) to provide an operational reforecast of rate year energy production at its Hopkins Ridge, Wild Horse, Wild Horse Expansion and LSR wind projects. According to Vaisala, an "operational reforecast is an independent assessment of the future production of an operating project based on the historical production data and the climate."[49] The historical production data relied on by Vaisala was the monthly average generation for each wind project. For Klondike III, the Company relies on a forecast provided by the site owner as opposed to the one developed by an independent consulting firm for PSE's owned facilities.

No, the Company did not submit the Vaisala studies with its direct case. Staff obtained it through discovery along with prior studies.

Q. Is this the first time PSE has derated the capacity factor of its wind resources?

A. No. For Hopkins Ridge alone, the Company adjusted the capacity factor downward three times since it was placed in service in 2005. For Wild Horse (in service in 2006), PSE has reduced its capacity factor twice. This case represents the first reductions of the capacity factors for PSE's recently added projects the Wild Horse Expansion (in service in 2009) and Lower Snake River (in service in 2011).

[49] Gomez, Exh. DCG-7C, PSE confidential Response to UTC Staff Data Request No. 176, Attachments C-F, Section 1- Introduction, ¶ 2.

Altogether, including this case, the Company has reduced the contribution of wind generation of all its wind plants in its power cost modeling by 192,000 MWhs (6.9 percent).

Q. Have other utilities regulated by the Commission also attempted to derate the energy production of its wind resources in its power cost modeling?

A. Yes. In its 2013 GRC PacifiCorp proposed a 12 percent reduction to the capacity factors for all four of its wind generation resources based on 48-months of historical data. The rate year impact of PacifiCorp's proposed derates in that case increased power costs by $1 million.[50] Staff opposed PacifiCorp's proposed derates on the basis that the observed historical data still fell within the original statistics which established those facilities' capacity factors at the time they were placed in service. On rebuttal, PacifiCorp dropped its proposal and restored its wind resource capacity factors to their original values. Staff provides the PacifiCorp derate proposal example to illustrate to the Commission that the issue of capacity factor derates for wind is likely to resurface, again, in future general rate cases.[51]

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[50] Gomez, Exh. DCG-13C, *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-130043, Staff testimony of David C. Gomez, Exh. DCG-1CT at 18:8 - 20:3. *See also* Gregory N. Duvall, Exh. GND-1CT at 17:8 - 18:15.

[51] The issue of modeling wind production, for the purposes of setting rates, is akin to the controversies which once surrounded hydro normalization. In *Wash. Utils. & Transp. Comm'n v. Avista Corporation d/b/a Avista Utilities*, Docket UE-050482, Order 05, ¶ 121 (Dec. 21, 2005), the Commission provided a summary of the hydro normalization issue:

> Hydro normalization methodology is a recurring issue in the Commission's general rate proceedings. The issue centers on how to determine the annual "average" amount of river water flow and the resulting amount of hydro-generation that will be available during the rate year. This is one of the factors critical to the power cost results determined using the AURORA power cost model.

Q. Does Staff support PSE's capacity factor derates for its wind resources?

A. No. For such a significant and material change to power costs, PSE dedicates only four questions and answers in Mr. Wetherbee's testimony to the subject. As for workpapers, the Company offers a single Excel spreadsheet with hard-coded, monthly estimates of potential net energy for its wind plants from its "Vaisala reforecast project." In Staff's view, PSE's direct evidence supporting its capacity derates for its wind resources contained in its prefiled and supplemental filings is woefully inadequate. As a result, Staff had to rely extensively on discovery to attempt to evaluate the Company's position on this issue. PSE effectively shifts the burden on to Staff and other parties to prove or disprove the appropriateness of derating wind resource capacity factors at a cost of millions of dollars to customers in the rate year.

Q. How did Staff evaluate PSE's proposed wind capacity factor derates?

A. Staff examined pre-construction forecasts, as well as the subsequent consultant reports all of which were provided by PSE through discovery. In addition, Staff reviewed Company witness testimony and exhibits supporting the capacity factor derates in both the 2007 and 2011 GRCs.

Q. Beginning with Hopkins Ridge, please provide the background history of PSE's reduction of capacity factors for its wind resources used to model rate year power costs.

A. The first change to Hopkins Ridge's capacity factor was made by PSE in its 2007 GRC (UE-072300) to account for wake losses from the construction of the nearby Marengo wind project. In UE-072300, PSE also included the capacity increases for Hopkins Ridge associated with the addition of four more turbines to the project's original 83 turbine configuration (Hopkins Ridge Infill). The full capacity benefit associated with the Hopkins Ridge Infill was limited at that time due to a BPA transmission constraint which restricted PSE's access to firm transmission.[52] Taking into account the additional turbines and wake loss effects from Marengo, Hopkins Ridge's capacity factor with firm transmission was set at 34.8 percent.

Four years later in its 2011 GRC, PSE reduced Hopkins Ridge's capacity factor again based entirely on a limited study conducted by the consulting firm DNV Renewables Inc. (DNV).[53] DNV did no additional data collection, but recommended a reduction to the capacity of Hopkins Ridge and Wild Horse simply because it used a different method for the calculation compared to the original study. DNV's estimate of Hopkins Ridge's capacity factor at 87 turbines was 32.6 percent. The combined effect of derating capacity factors for both Hopkins Ridge and Wild Horse

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[52] Staff also evaluated the status of transmission constraints on the BPA system which had limited the output of Hopkins Ridge in 2007. In Mr. Wetherbee's workpapers it shows PSE holding 154 MW of firm Point-to-Point transmission for Hopkins Ridge which Staff assumes to mean that the constraint no longer applies. Staff also confirmed completion of BPA's West of McNary system upgrades which PSE had identified as the source of the constraint.

[53] Gomez, Exh. DCG-9C, PSE's confidential Response to UTC Staff Data Request No. 176, Attachment G. DNV's report for both Hopkins Ridge and Wild Horse describes the study as a preliminary evaluation of the net energy estimates based on a review of the pre-construction consultant's report. DNV goes on to say that it "did not independently analyze the raw wind data, assess the energy production, or evaluate the uncertainties" associated with the preconstruction energy assessment. DNV concluded in its study that the pre-construction estimates were reasonable yet recommended a lower capacity factor primarily due to differences in methodology in how each consultant calculates energy loss estimates.

was a reduction in the amount of wind generation in the rate year of almost 65,000 MWhs (5.9 percent). According to the Company's testimony in the 2011 GRC, the AURORA model replaced this lost wind production with market purchases increasing rate year power costs in that case by $2.0 million.[54] DNV's capacity factor estimate for Hopkins Ridge and Wild Horse was also used in the Company's 2014 PCORC to model rate year power costs.

For this case, PSE presents the results of yet another study of Hopkins Ridge to justify a further reduction to the plant's capacity factor. According to Mr. Wetherbee, Vaisala's estimate of Hopkins Ridge's capacity factor relied on 10-years of historical production data. Examining the actual report shows Vaisala was provided by PSE with monthly MWh averages of Hopkins Ridge generation spanning a period of 128-months. Vaisala stated in the report that it tossed out 22 of those months to account for what it said was a break-in period (8-months) and also rejected months where the data indicated that plant availability fell below 90 percent (14-months). Later in the report, Vaisala provides its reforecast results citing it used 80-months of observed, normalized production data. Which months were used and by what criteria more months were rejected are unexplained. Vaisala's estimated capacity factor for Hopkins Ridge in the 2018 rate year is 30.1 percent.

[54] Gomez, Exh. DCG-15C, *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, prefiled direct testimony of David E. Mills, Exh. DEM-1CT at 19:13 - 21:6.

Q. What capacity factor should be used for Hopkins Ridge?

A. Staff's position is that the 34.8 percent capacity factor established in the 2007 GRC for the current 87 turbine configuration at Hopkins Ridge should be used as opposed to the 30.1 percent PSE used in AURORA to calculate power costs in this case. The DNV and Vaisala reports are unconvincing and leave Staff with many unanswered questions. For example, why did PSE decide to use a monthly average for the entire plant in its study versus actual turbine specific data produced every 10-minutes by the Supervisory Control and Data Acquisition (SCADA) system? Did PSE attempt to compare the SCADA data against the pre-construction statistics to determine whether the plant is operating within its expected parameters and; if not, why? Did Vaisala's 2016 report account for the effects of a strong El Niño which had a significant impact in 2015, contributing to wind speeds that were significantly below normal throughout much of the U.S particularly in the West?[55] What are the expected impacts to performance associated with the advancing age of Hopkins Ridge's turbines and how does the $6.6 million in rate year O&M costs for this plant presented in Mr. Robert's testimony mitigate this?[56] Nor can Staff reconcile what little evidence the Company did provide with its statements about wind resource capacity factors in its 2015 IRP.[57]

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[55] Gomez, Exh. DCG-10, *2015 Wind Technologies Market Report*, U.S. Department of Energy (August 2016), Inter-Year Wind Resource Variability, p. 41.

[56] Roberts, Exh. RJR-1CT at 69:10, Table 5.

[57] Mullally, Exh. MM-11, Appendix N, p. 22, the Company's 2015 IRP illustrates the frequency of the annual capacity factor for a 100 MW generic wind project based on the performance of Hopkins Ridge, Wild Horse and Lower Snake River. Figure N-13 summarizes the distribution of capacity factors that resulted from 250 simulations for each of the calendar years in the IRP's planning horizon. A median capacity factor of 34 percent is the assumption PSE uses throughout its IRP in evaluating the acquisition of wind against other resource options.

Staff's view is 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. This equal sharing of risk and reward is consistent with how the PCA mechanism is designed to work. Constant downward forecasts by the Company defeat this purpose. Further, the Company already accounts for the costs of wind resource variability outside the AURORA model in its wind integration costs which I discussed earlier in my testimony.[58]

Q. Can you briefly describe the reductions the Company has made to the other wind resource capacity factors in the AURORA model in this case?

A. As mentioned previously, PSE has reduced Wild Horse's capacity factor twice (including this case) since it was placed in service. In the 2011 GRC, Wild Horse's capacity factor was reduced to 30.2 percent from its pre-construction forecast of 32.0 percent. In this case, the Company uses 29.4 percent as the capacity factor.

For Wild Horse Expansion, PSE reduces its original capacity factor of 23.8 percent to the 23.5 percent in this case. LSR was reduced from 29.9 percent to 28.3 percent. Finally, for Klondike III, PSE reduces its capacity factor from 36.4 percent to 30.0 percent.

[58] *Supra* Section VII.A.

Q. Are the concerns with these wind resource reductions the same as the concerns with the derating of Hopkins Ridge?

A. Yes. PSE has failed to meet the burden of proof that its wind resources are not performing as expected given the variability statistics offered by the Company at the time they were placed in service and the Commission deemed them prudent.

Q. What is your recommendation for the remaining wind resources which PSE derated in this case?

A. The Commission should require PSE to restore the original preconstruction capacity factors in the AURORA model when it provides its final power cost update at the end of this case. The capacity factors of the wind farms should be:

Wild Horse	32.0 percent
Wild Horse Expansion	23.8 percent
LSR	29.9 percent
Klondike III	36.4 percent

D. Contingent Power Cost Calculation

Q. What is the purpose of PSE's contingent power cost calculation?

A. A contingent power cost calculation was included in the Company's power cost update in PSE's supplemental filing of April 3, 2017. The purpose of including a contingent power cost calculation is to account for Microsoft's departure from PSE's Schedule 40 when it begins taking retail wheeling service under a special contract.

Upon Microsoft's departure, PSE's remaining customers will receive a stranded cost payment while, at the same time, the Company will adjust its power costs to reflect the loss of Microsoft's load. According to Mr. Wetherbee, PSE's rate year power costs with Microsoft's load is $737.7 million and $724.3 million without.

Q. Did Staff evaluate PSE's contingent power cost calculation?

A. Yes. In Mr. Wetherbee's supplemental Exh. PKW-14C, the projected effect on power costs in the rate year resulting from Microsoft's departure is a reduction in expense of $13.4 million. The reduction is almost entirely based on AURORA model results that decrement market purchases in the rate year as a result of Microsoft's departure.

Q. PSE is requesting the Commission approve its contingent power cost calculation in this proceeding. Does Staff support this?

A. No. Staff agrees with PSE that the transition of Microsoft from Schedule 40 to its special contract within the rate year can be done expeditiously and easily. However, the Company's AURORA model results supporting its contingent power cost calculation is dependent on natural gas and market prices for electricity which may change either up or down by the time Microsoft is ready to begin taking retail wheeling service and, therefore, have a material effect on rates. Also, if the Commission adopts Staff's recommended adjustments to power costs in this case, they will also need to be factored into PSE's contingent power cost calculation.

Q. What is Staff's recommendation?

A. Staff recommends the Commission require the Company, on compliance, to update its power costs prior to rates taking effect in this case. This update would include Staff's proposed adjustments along with a re-run of the AURORA model to reflect the most recent forecasts for natural gas and market prices for electricity.

Given that the exact time of Microsoft's departure is unknown, any subsequent update to power costs within the rate year should also include a refresh of these forecasts. Staff is confident that it can review the updated AURORA results and complete its examination in order to allow the Commission to approve rates within the 30-day window proposed by the Company.

Q. Does this conclude your testimony?

A. Yes.