EXH. PKW-1CT
DOCKETS UE-19___/UG-19___
2019 PSE GENERAL RATE CASE
WITNESS: PAUL K. WETHERBEE

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-19____** **Docket UG-19____**

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF

PAUL K. WETHERBEE

ON BEHALF OF PUGET SOUND ENERGY

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VERSION

JUNE 20, 2019

PUGET SOUND ENERGY

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PAUL K. WETHERBEE

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PUGET SOUND ENERGY

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I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy.

A. My name is Paul K. Wetherbee. My business address is 355 110th Avenue NE, Bellevue, Washington, 98004. I am the Director, Energy Supply Merchant for Puget Sound Energy ("PSE").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. Please see the First Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-2, for an exhibit describing my education, relevant employment experience, and other professional qualifications.

Q. What are your duties as Director, Energy Supply Merchant?

A. As Director, Energy Supply Merchant, my responsibilities include the following:

(i) managing the dispatch of PSE's portfolio of generation assets, related transmission, and associated environmental attributes;

(ii) directing the front office power and gas trading operations and the hedging program functions; and

(iii) oversight of the long-term gas transport capacity position.

Q. Please summarize the contents of your testimony.

A. This prefiled direct testimony addresses the following issues relevant to power costs for this proceeding's rate year—May 1, 2020 through April 30, 2021 (the "rate year"):

(i) an overview of PSE's power costs and how they are managed;

(ii) renewal and addition of transmission contracts with Bonneville Power Administration ("BPA");

(iii) the extension of PSE's gas-for-power transportation contracts, which provide access to natural gas resources for its natural gas-fired generation facilities;

(iv) changes to existing generation resources and new resources that impact power costs;

(v) treatment of the costs and benefits of PSE's participation in the Energy Imbalance Market ("EIM");

(vi) PSE's methodology for estimating rate year power costs, including proposed changes;

(vii) PSE's projected rate year power costs for this proceeding, including changes in resources available to PSE to meet customer demand; and

(viii) a comparison of PSE's projected rate year power costs for this proceeding to those currently in rates and calculated using the prior method.

II. POWER COSTS OVERVIEW

Q. What is included in PSE's power costs?

A. Power costs include the costs of fuel to run generating units, purchased power, and third party transmission. Specifically, power costs include costs of coal, gas and oil to run thermal generators, long term power purchase agreements, other market purchases and sales, fixed and variable costs of upstream natural gas transportation and storage, BPA transmission, and various other costs.

Q. What is the basis for the power cost rates that are in place today?

A. Current rates were established in PSE's last general rate case, Docket UE-170033 (the "2017 GRC"). Power costs were agreed to in a multiparty settlement (the "2017 GRC Settlement") in that proceeding, and the rates went into effect December 19, 2017. In that case, PSE presented power costs with and without the Microsoft load previously served under Schedule 40. The power costs from the 2017 GRC that excluded the Microsoft load previously served under Schedule 40 were established in rates in Docket UE-190166, effective May 1, 2019.

Q. What level of power costs does PSE propose and how do the proposed costs compare with costs from the 2017 GRC Settlement?

A. The Second Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-3C, provides a summary of PSE's proposed power costs in comparison with power costs in the 2017 GRC Settlement. PSE's power cost projections for the rate year of $743.5 million are 4.5 percent higher than the amount set in rates ($711.5 million) effective December 19, 2017. The primary drivers of these increased costs are:

(i) two new power purchase agreements to serve Green Direct customers, with the Skookumchuck Wind Energy Project (the "Skookumchuck PPA") and Lund Hill Solar Project (the "Lund Hill PPA");

(ii) a scheduled rate increase in the Coal Transition Power Purchase and Sale Agreement ("Coal Transition Power") with Transalta Centralia Generation;

(iii) increased gas transportation costs driven by scheduled rate increases on Northwest Pipeline effective in October 2018 and tariff increases on Westcoast Energy pipeline effective in January 2019;

(iv) costs related to BPA transmission contracts; and

(v) increases to other power supply expenses.

These costs are partially offset by lower costs of fuel for PSE's gas fired generation resources. The Skookumchuck PPA and the Lund Hill PPA are presented in the Prefiled Direct Testimony of William T. Einstein, Exh. WTE-1CT.

Q. What is the nature of PSE's load and resources to serve that load?

A. PSE's electric load is primarily driven by residential and commercial customers, with a portion coming from industrial customers. Forecasted load for the rate year is 2,643 average megawatts ("aMW") with a peak monthly demand of 4,936 megawatts ("MW"). The difference between average energy and peak demand illustrates the seasonal nature of PSE's load.

PSE owns a mix of thermal, wind and hydroelectric resources to serve its load. These resources alone are not sufficient to meet customer demand in all hours of the year. Therefore PSE relies on contracts with non-utility generators and market purchases to meet its load. PSE holds transmission capacity that enables it to buy and sell power on the market, primarily at the Mid-Columbia ("Mid-C") trading hub. This reliance on market purchases means PSE is exposed to spot market prices for power and gas.

Q. What resources does PSE have to meet its customer load and manage its power costs?

A. PSE owns a diverse portfolio of generating assets that includes the following resources (at nameplate capacities):

(i) 677 MW of large, base-load coal generation with low variable fuel costs;

(ii) 1,307 MW of gas-fired, combined-cycle combustion turbines with moderate heat rates;

(iii) 615 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbine generation;

(iv) 263 MW of hydroelectric generation; and

(v) 772 MW of wind generation.

In addition, PSE holds power purchase agreements for 630 MW of hydroelectric generation at Mid-C and approximately 810 MW of other resources.

Q. What factors drive volatility and risk in the power portfolio?

A. The following drivers of power and gas price volatility impact power costs:

(i) streamflow variation affecting the supply of hydroelectric generation;

(ii) weather and economic uncertainty affecting power usage;

(iii) risk of forced generation outages;

(iv) contract obligations;

(v) variable energy resources;

(vi) market volatility; and

(vii) transmission and transportation constraints.

All of these have an impact on load and resources, which PSE may balance with wholesale market purchases and sales.

Q. What governance does PSE have to manage power cost risk?

A. PSE's Energy Management Committee ("EMC") is a group of officers who provide oversight of portfolio management activities. PSE's Energy Supply Transaction and Hedging Procedures Manual and Energy Risk Policy establish the policies that govern energy portfolio management activities and define roles and responsibilities of various departments. The Risk Control, Analytics & Credit department performs the middle office functions of monitoring Energy Supply Merchant department activities for compliance with policies and managing risk.

Q. What actions does PSE take to manage its power costs within that governance structure?

A. PSE uses a combination of least cost dispatch, optimization, and portfolio hedging to manage power costs.

Q. Please explain least cost dispatch.

A. The Energy Supply Merchant department plans for sufficient generation capacity to meet the forecasted day-ahead demand for electricity plus a reserve margin. PSE uses a least-cost dispatch approach for all resources, considering transmission and generation constraints. This strategy minimizes portfolio costs by seeking the most economic supply, whether generated or purchased in the wholesale market.

Q. Please explain optimization.

A. Given PSE's resource adequacy planning standard to meet peak hour loads, many days out of the year there is excess capacity. To optimize the portfolio, the Energy Supply Merchant department sells excess energy, fuel, transmission, generation, and natural gas pipeline capacity (not utilized for load) into the regional markets. Portfolio optimization activities align with PSE's Energy Risk Policy and Energy Supply Transaction and Hedging Procedures Manual.

Q. Please explain portfolio hedging.

A. The purpose of hedging is to reduce the effects of price volatility in power costs prior to delivery. PSE's hedging program reduces exposure to power and natural gas price risk in more volatile spot markets. PSE uses a combination of programmatic and actively managed strategies in its hedging program. The Programmatically Managed Hedge period begins [redacted] in advance of delivery. The Energy Supply Merchant department uses the Programmatically

Managed Hedge program to systematically reduce PSE's net power portfolio exposure until a particular month rolls into the Actively Managed Hedge period. The Actively Managed Hedge program begins [redacted] in advance of delivery. During this period, the Energy Supply Merchant department monitors positions and executes transactions to manage exposure within PSE's Energy Risk Policy and Energy Supply Transaction and Hedging Procedures Manual.

Q. What are the hedges included in rate year power costs?

A. The rate year power costs include gas-for-power and power contracts that were transacted as of January 31, 2019, for delivery during the rate year (May 1, 2020 through April 30, 2021).

Table 1 below provides a summary of the fixed-price rate year power portfolio hedges included in rate year power costs.

**Table 1. PSE's 2019 GRC Rate Year
Short-Term Fixed Price Power Portfolio Hedges
at January 31, 2019**

	MWh Volume	Rate Year Cost	Avg. $/MWh
On-Peak Power Purchases	[redacted]	$[redacted]	$[redacted]
	Dth Volume	**Rate Year Cost**	**Avg $/Dth**
Net Financial Gas for Power	[redacted]	$[redacted]	$[redacted]

As discussed below, to determine rate year power costs, PSE (i) marked to market the fixed-price gas-for-power contracts in the "Costs Not in AURORA" calculation and (ii) included the fixed-price power contracts within the AURORA model.[1] In addition, PSE has entered into physical gas-for-power contracts for the rate year which are priced at plus or minus index. The premiums and/or discounts for index contracts are also included in the "Costs Not in AURORA" calculation.

Q. Please expand on the types of hedges included in rate year power costs.

A. PSE hedges power or gas-for-power to fix the price of the commodity. PSE utilizes either fixed-for-float swaps[2] to financially hedge power and natural gas-for-power or fixed price physical power and gas for power. The mechanics of a financial fixed-for-float swap, in combination with a physical index purchase, result in a fixed position identical to purchasing fixed price physical supply.

PSE is able to transact with counterparties through standard agreements for financial swaps and fixed price physical power. PSE's market counterparties may be able to sell physically, financially, or, in some cases, both. Therefore, liquidity is enhanced by transacting both physically and financially.

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[1] The AURORA model is discussed in Section VII of this prefiled direct testimony.

[2] Fixed-for-float swaps fix the price of a commodity relative to the market "index" price of a commodity and settlement is done financially. For example, PSE may enter into a fixed-for-float Mid-C power contract for a future month at a fixed price of $32.00 per MWh for all hours of the day ("flat"). When the future month occurs, the contract is settled by comparing the fixed $32.00 per MWh to the market price of, say $35.00 per MWh. In this example, the counterparty would pay PSE the difference between the fixed price and the market price, or $3.00 per MWh. For a 31-day month with 744 hours, this would be a payment of $2,232 for a 1 MW contract.

III. TRANSMISSION CONTRACT RENEWALS AND ADDITIONS

Q. Please provide an overview of the transmission contracts renewed or acquired for the rate year.

A. PSE uses transmission to wheel power from both its owned and contracted resources to PSE's system to serve load. In addition to relying on its own transmission, PSE also relies extensively on BPA transmission contracts to transmit generated or purchased power to PSE's system so that PSE may meet customer demand and ensure power is provided continuously during a peak demand event. A large portion of the BPA transmission is used to wheel short-term market purchases at the Mid-C hub to meet PSE's capacity need as explained in PSE's 2017 Integrated Resource Plan (the "2017 IRP").[3] These transmission contracts are an integral part of PSE's electric resource portfolio and are necessary to provide capacity and energy. This testimony addresses:

- renewal of fourteen BPA transmission contracts for delivery from the Mid-C hub;
- three new BPA transmission contracts to be used to access short-term market purchases at the Mid-C hub and long-term Mid-C generation contracts;
- renewal of eight BPA transmission contracts to allow for continued delivery from existing generation resources;

[3] *See* Puget Sound Energy, Inc., 2017 Integrated Resource Plan, Chapter 6 (Electric Analysis) (November 2017), available at https://www.pse.com/pages/energy-supply/resource-planning.

- two new BPA transmission contracts starting in 2024 for an existing PSE facility, Hopkins Ridge Wind Facility;[4]

- renewal of two BPA transmission contracts to serve PSE's load at Clymer substation; and

- renewal of three BPA transmission contracts from the John Day Substation and one BPA transmission contract to the John Day Substation for the PG&E Energy and Capacity Exchange Agreement.

Q. Has PSE prepared a summary of transmission renewals and additions for the rate year?

A. Yes. Table 2 shows BPA transmission contracts that have expired or will expire before the end of the rate year, as well as new transmission contracts with BPA.

[4] The current transmission contracts for Hopkins Ridge are due to expire in 2024.

Table 2. BPA Transmission Contract Renewals & Additions
Mid-C Transmission Renewals and Additions

Receipt Point	Assigned Reference No.	Renewal Deadline	Start Date	MW Capacity
Midway	85094840	10/1/2017	10/1/2018	115
Midway	85094872	3/1/2018	3/1/2019	35
Subtotal Midway				**150**
Rocky Reach	87646738	11/1/2018	11/1/2019	40
Rocky Reach	87646744	11/1/2018	11/1/2019	40
Rocky Reach	87646822	11/1/2018	11/1/2019	40
Rocky Reach	87651165	11/1/2018	11/1/2019	5
Rocky Reach		11/1/2018	11/1/2019	55
Subtotal Rocky Reach				**180**
Vantage	87646884	12/1/2018	12/1/2019	169
Vantage	87646863	11/1/218	11/1/2019	27
Vantage	87646865	11/1/218	11/1/2019	27
Vantage	87646870	11/1/218	11/1/2019	27
Vantage	87646876	11/1/218	11/1/2019	3
Vantage	87648173	11/1/218	11/1/2019	36
Vantage	87646883	11/1/218	11/1/2019	5
Subtotal Vantage				**294**
Vantage	78510685	New (Partial)	12/1/2019	50
Wells/Sickler	78297205	New	11/1/2018	50
Vantage	78297196	New	11/1/2018	50
Subtotal New Contracts				**150**
Total Mid-C Renewals and Additions				**774**

Transmission Renewed or Added for Resources

Resource	Assigned Reference No.	Renewal Deadline	Start Date	Megawatt Capacity
Colstrip	86749655	8/1/2018	8/1/2019	263
Colstrip	86749660	8/1/2018	8/1/2019	100
Colstrip	86749663	8/1/2018	8/1/2019	300
Wells	87215511	9/1/2017	9/1/2018	69
Wells	87215515	9/1/2017	9/1/2018	69
Wells	87215520	9/1/2017	9/1/2018	128
Goldendale (Partial)	86514454	3/1/2018	3/1/2019	21
Goldendale (Partial)	86876134	3/1/2018	3/1/2019	6
LSR (Central Ferry)	82996277	New	3/1/2024	79
Hopkins (Tucannon)	82996217	New	3/1/2024	75
Total for Resources				**1,110**

Transmission Renewed for Load or Contract Agreement

Resource	Assigned Reference No.	Renewal Deadline	Start Date	Megawatt Capacity
Clymer (Anderson Hay)	87054282	11/1/2018	11/1/2019	1
Clymer (Anderson Hay)	87054289	8/1/2018	8/1/2019	4
PG&E (N>S)	87053665	8/1/2018	8/1/2019	300
PG&E (S>N)	87054225	8/1/2018	8/1/2019	100
PG&E (S>N)	87054255	8/1/2018	8/1/2019	50
PG&E (S>N)	87054272	8/1/2018	8/1/2019	150
Total for Load or Contracts				**605**

A. Transmission Contract Renewals & Additions

1. Mid-C Transmission Renewals

Q. How does PSE determine the appropriateness of renewing firm Mid-C transmission?

A. As Mid-C transmission contracts become eligible for renewal, PSE evaluates the costs and risks of Mid-C resources using a similar approach and the same tools it uses to evaluate generation assets for acquisition. PSE compares the cost of transmission contracts to other resource alternatives to fill in resource need based on models developed in the Integrated Resource Plan.

Q. When does PSE evaluate the Mid-C transmission renewals?

A. PSE evaluates the costs and benefits of renewing its Mid-C transmission contracts one year and two months prior to their expiration date. Renewing a current transmission contract one year prior to expiration enables PSE to execute a right of first refusal. The two additional months are required for PSE to meet its internal review process. The analysis is presented to the EMC twice. The first presentation is to explain the analysis and request for decision. The second, or final, presentation is a decisional presentation at which the EMC members vote to decide if the transmission contract purchase or renewal should be made.

PSE will continue to evaluate Mid-C transmission contracts and will have the opportunity to make adjustments to its total Mid-C transmission capacity available to meet customers' peak capacity need as other Mid-C transmission contracts come up for renewal. At that time, PSE will have the option to reduce its Mid-C transmission capacity if new information results in a different conclusion than analysis of previous renewals.

a. Mid-C 150 MW Transmission Renewals

Q. Please describe PSE's 150 MW Mid-C transmission contracts with BPA.

A. PSE has two existing Mid-C transmission contracts (115 MW and 35 MW) originating at the Midway Substation located in Benton County, Washington, that expired in October 2018 and March 2019, respectively. PSE renewed these two contracts for the minimum term of five years to retain renewal rights and to allow flexibility to reevaluate transmission needs in the future. If PSE does not renew these contracts, it may be difficult to get back the transmission capacity in the future. PSE manages the risk of not getting capacity in the future by renewing contracts at their renewal deadlines.

Q. Please summarize PSE's approach to the analysis related to renewing the 150 MW Mid-C firm transmission contracts from the Midway Substation.

A. PSE compared (i) the incremental portfolio cost of generation resources assuming renewal of the 150 MW transmission contracts with (ii) the incremental portfolio cost of the generation resources assuming expiration of the contract. PSE used this comparison to determine whether there was an economic benefit to renewing the transmission contracts.

PSE's incremental portfolio cost of generation includes variable costs of PSE's existing generation assets, all capital and operating and maintenance costs associated with new units necessary to meet peak capacity and Renewable Portfolio Standard ("RPS") requirements over 20 years, and end effects of new resources. End effects include residual costs of the new resources beyond the 20-year window through the useful life of the assets plus the replacement costs for those assets.

Q. How does PSE calculate the portfolio costs?

A. PSE calculates the portfolio costs on a net present value basis using the Portfolio Screening Model III ("PSM III"). PSM III is an optimization model PSE uses to identify the least cost portfolio on a net present value basis that meets both its peak capacity and RPS requirements. PSE also uses PSM III to develop its Integrated Resource Plan and to evaluate bids for generation resources provided by outside parties in response to Requests for Proposals. The PSM III model contains data from the 2017 IRP and ongoing Integrated Resource Plan work. The model includes data on PSE-owned resources and forecasted load, financial data, forecasted dispatch from the AURORA production cost model, and costs of alternative resources such as natural gas-fired combined cycle units, peaking units and wind resources.

Q. Please describe the AURORA dispatch model.

A. AURORA is a fundamentals-based production cost model that simulates hourly economic dispatch of generation resources. PSE uses it to model the Western Interconnection of the United States. PSE uses energy, cost, revenue and price data related to PSE assets and potential new assets from the AURORA model in its PSM III model.

Q. What were the results of the analysis?

A. The analysis showed that renewing the 150 MW Mid-C transmission contracts resulted in a lower portfolio cost as compared to allowing the transmission contracts to expire in October 2018 and March 2019. PSE used two scenarios to evaluate these contracts, with and without carbon pricing. With carbon pricing, renewing these contracts reduced the net present value of portfolio costs $58 million compared to allowing the contracts to expire. Without carbon pricing, renewing these contracts reduced the net present value of portfolio costs $85 million compared to allowing the contracts to expire.

Q. Why is there a portfolio benefit to the transmission contract renewals?

A. The transmission contracts with BPA allow PSE to delay building some generation capacity during the planning horizon, which results in a lower net present value of portfolio costs.

Q. Did PSE's EMC approve the renewal of the 150 MW of transmission contracts at the Midway Substation?

A. Yes. The EMC approved renewal of the 150 MW of transmission at the Midway Substation on June 15, 2017. The Third Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-4, presents the slides that were presented to the EMC supporting these contract renewals.

b. Mid-C 474 MW Transmission Renewals

Q. Please describe PSE's 474 MW Mid-C transmission contracts with BPA.

A. PSE has twelve existing Mid-C transmission contracts totaling 474 MW (180 MW originating at the Rocky Reach Substation and 294 MW originating at the Vantage Substation in Grant County, Washington) with expiration dates in December and November 2019. PSE has renewed these twelve contracts for the minimum term of five years to retain renewal rights and to allow flexibility to reevaluate transmission needs in the future. If PSE does not renew these contracts, it may be difficult to get back the transmission capacity in the future. PSE manages the risk of not getting capacity in the future by renewing contracts at their renewal deadlines.

Q. Please summarize PSE's approach to the analysis related to renewing the 474 MW of Mid-C firm transmission contracts.

A. PSE analyzed these contracts using the same approach it used to evaluate the 150 MW of Mid-C contracts discussed above.

Q. What were the results of the analysis?

A. The analysis showed that renewing the twelve Mid-C transmission contracts resulted in a lower portfolio cost compared to allowing the transmission contracts to expire in October - November 2019. The net present value of portfolio costs with renewal was $195 million lower than the net present value of portfolio costs without renewal.

Q. Did PSE's EMC approve the renewal of the 474 MW of transmission contracts at the Rocky Reach Substation and the Vantage Substation?

A. Yes. The EMC approved renewal of the 474 MW of transmission at the Rocky Reach Substation and the Vantage Substation on August 21, 2018. The Fourth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-5, presents the slides that were presented to the EMC supporting these contract renewals.

2. Mid-C 150 MW New Transmission

Q. Please describe PSE's new 150 MW Mid-C transmission contracts with BPA.

A. In 2013, PSE submitted three requests of 50 MW each (totaling 150 MW) to BPA for Mid-C transmission. This request was based on the 2013 Integrated Resource Plan, which indicated a capacity need in 2020. In October 2017, BPA was able to grant two of the requests as long-term firm PTP transmission contracts. PSE accepted the two new Mid-C PTP transmission contracts, each of 50 MW, for a minimum term of five years to retain renewal rights and to allow flexibility to reevaluate transmission needs in the future. Additionally, PSE accepted one new Mid-C PTP transmission contract of 50 MW on a partial firm basis. PSE has requested to change the status from partial firm to long-term firm transmission when Available Transfer Capability ("ATC") becomes available.

Q. Please summarize PSE's approach to the analysis related to acquiring 150 MW of new Mid-C firm transmission contracts.

A. PSE analyzed these new contracts using the same approach it used to evaluate the 150 MW Mid-C contract renewals, using a model assuming the Clean Air Rule was in effect. PSE compared the portfolio cost with the new transmission under two scenarios: (i) the use of seasonal redirects of transmission to Mid-C from the Lower Snake River and Hopkins Ridge Wind Facilities to partially mitigate the need to meet winter peak capacity needs, and (ii) the addition of thermal resources to meet the need.

Q. What are seasonal redirects and how do they work?

A. BPA allows its customers to request an alternate point of reciept and/or point of delivery for any confirmed point-to-point firm transmission service request, that is, move the reserved firm transmission from the reserved path to an alternate path. PSE uses redirects of its long term transmission reservations on BPA's transmission system to provide power to PSE's load at the lowest available cost. Sometimes, redirects are seasonal due to PSE's preference or feasibility constraints of alternate paths on BPA's transmission system.

Q. What were the results of the analysis?

A. The analysis showed that acquiring the three additional Mid-C PTP transmission contracts, totaling 150 MW, resulted in a lower portfolio cost compared to a new gas peaker plant or seasonal redirects of transmission from wind generating stations in the winter months. The analysis compared the impact of adding additional BPA transmission versus thermal plants under two different scenarios, which were with and without transmission redirects. With transmission redirects, adding the 150 MW of new BPA transmission reduced the net present value of portfolio costs $40 million. Without transmission redirects, adding the new transmission reduced the net present value of portfolio costs $58 million.

Q. What are some of the risks associated with acquiring new Mid-C firm transmission in the future?

A. New Mid-C firm transmission is requested through BPA's transmission queue and requires participation in a future Transmission Service Request Study and Expansion Process, formerly known as Network Open Season, if BPA is unable to grant the transmission due to a lack of Available Transfer Capability on the requested transmission path. The BPA Transmission Service Request Study and Expansion Process that concluded in May 2018 showed that current Transmission Service Requests requesting service from the Mid-C will impact a constrained transmission path. New Mid-C firm transmission requests require capacity on multiple constrained BPA flowgates. The most prominent BPA flowgate affecting a new Mid-C firm transmission request is the Cross-Cascades North flowgate. The Cross-Cascades North flowgate is highly constrained, with no available winter month capacity through 2029, as posted on the BPA website.

Q. Did PSE's EMC approve the acquisition of the 150 MW of Mid-C PTP transmission contracts?

A. Yes. The EMC approved the 150 MW of Mid-C PTP transmission contracts on October 19, 2017. The Fifth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-6, presents the slides that were presented to the EMC supporting these transmission contracts.

3. Existing Generation Resource/Load Transmission Renewals

Q. Did PSE renew any BPA transmission contracts used to wheel power from existing resources?

A. Yes. PSE renewed three transmission contracts to allow continued delivery of power from the Colstrip Generating Station, three contracts to wheel power from the Wells Hydroelectric Project (the "Wells Project"), and two partial contracts related to the Goldendale Generating Station. The eight contracts are listed in Table 3 and described below.

Table 3. BPA Existing Generation Transmission Renewals

Resource	Assigned Reference No.	Renewal Deadline	Start Date	Megawatt Capacity
Colstrip	86749655	8/1/2018	8/1/2019	263
Colstrip	86749660	8/1/2018	8/1/2019	100
Colstrip	86749663	8/1/2018	8/1/2019	300
Subtotal Colstrip				**663**
Wells	87215511	9/1/2017	9/1/2018	69
Wells	87215515	9/1/2017	9/1/2018	69
Wells	87215520	9/1/2017	9/1/2018	128
Subtotal Wells				**266**
Goldendale	86514454	3/1/2018	3/1/2019	21
Goldendale	86876134	3/1/2018	3/1/2019	6
Subtotal Goldendale				**27**
Total				**956**

PSE also renewed two BPA transmission contracts to serve PSE's off-system load and four BPA transmission contracts to serve the Pacific Gas & Electric (PG&E) Capacity and Energy Exchange Agreement. These six transmission contracts are listed in Table 4 and described below.

Table 4. BPA Existing Load Serving Transmission and Agreement Transmission Renewals

Resource	Assigned Reference No.	Renewal Deadline	Start Date	Megawatt Capacity
Clymer (Anderson Hay)	87054282	11/1/2018	11/1/2019	1
Clymer (Anderson Hay)	87054289	8/1/2018	8/1/2019	4
PG&E (N>S)	87053665	8/1/2018	8/1/2019	300
PG&E (S>N)	87054225	8/1/2018	8/1/2019	100
PG&E (S>N)	87054255	8/1/2018	8/1/2019	50
PG&E (S>N)	87054272	8/1/2018	8/1/2019	150
Total				**605**

a. Transmission Contract (663 MW) Serving Colstrip

Q. Please describe the 663 MW contract serving the Colstrip Generating Station.

A. The Colstrip Generating Station is an existing resource. The facility is interconnected to BPA's transmission system through the Colstrip Transmission System and BPA's Townsend – Garrison 500 kV lines. Power from the Colstrip Generating Station is wheeled to PSE's system through the Colstrip Transmission System, BPA's Townsend – Garrison 500 kV lines, and 663 MW of BPA main grid transmission contracts. The three BPA main grid transmission contracts expire in July 2019. PSE renewed the three BPA transmission contracts for five years to retain renewal rights and to allow continued delivery of power from the Colstrip Generating Station.

Q. What does PSE intend to do with 300 MW of BPA main grid transmission contracts associated with Colstrip Units 1 and 2 when the resources close?

A. After Colstrip Units 1 and 2 close, 300 MW of BPA transmission will continue to be of value as it offers flexible options including (i) redirect to Mid C hub for PSE winter peaking capacity, (2) redirect in BPA's main grid for a new resource in PSE's RFP process, or (3) be repurposed for delivery of renewable resources to meet the requirements of the Clean Energy Transformation Act, Engrossed Second Substitute Senate Bill 5116. By renewing the contracts to 2024, PSE will retain rollover rights and will be able to proactively submit redirect requests to BPA if needed.

Q. Did PSE's EMC approve the renewal of the 663 MW of BPA transmission related to Colstrip?

A. Yes. The EMC approved the 663 MW of Colstrip transmission contracts on February 15, 2018. The Sixth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-7, presents the slides that were presented to the EMC supporting these transmission contracts.

b. Mid-C 266 MW Transmission Renewals for Wells

Q. Please describe PSE's 266 MW Wells (Mid-C) transmission contracts with BPA.

A. PSE has a power purchase agreement with Public Utility District No. 1 of Douglas County, Washington ("Douglas PUD") for output from the Wells Hydroelectric Project (the "Wells Project") through September 2028. The 266 MW Wells Project BPA transmission contract was originally part of an Integrated Resource ("IR") contract with BPA to facilitate flow of PSE's contracted Wells Project generation to PSE's load. The IR transmission contract expired on August 31, 2018, and BPA converted the IR transmission contract to three Point-to-Point Transmission ("PTP") contracts totaling 266 MW starting September 1, 2018, pursuant to the BPA Open Access Transmission Tariff ("OATT") contracts with BPA. The transmission contract renewal allows PSE to continue to take delivery of Wells Project contracted generation. These three contracts are for a minimum term of five years to retain renewal rights and to allow flexibility to reevaluate transmission needs in the future.

c. Transmission Contracts (27 MW) Associated with the Goldendale Generating Station

Q. Please describe the 27 MW contracts associated with the Goldendale Generating Station.

A. In March 2018, PSE requested renewal of 27 MW of an existing BPA transmission contract for wheeling power from the Goldendale Generating

Station. However, the renewal request missed the one-year deadline to retain rollover rights. Since there was no ATC to grant the request, BPA granted partial firm transmission expiring in November 2021. PSE has requested to convert the partial firm transmission to long-term firm transmission.

Q. Are costs associated with the 27 MW contract for the Goldendale Generating Station included in rate year power costs?

A. Yes. Rate year power costs associated with this contract are $599,400.

d. Two Transmission Contracts Serving Clymer Substation

Q. Please describe the 1 MW and 4 MW contracts associated with PSE's load pocket at the Clymer Substation.

A. PSE has a pocket of load served by its Clymer Substation interconnected to BPA's main grid transmission system. Power from PSE's system is wheeled to this load through 5 MW of BPA transmission contracts, which are scheduled to expire in August and November 2019. PSE has renewed the contracts for five years to retain renewal rights and to allow continued delivery of power to the Clymer Substation.

e. BPA Transmission Contracts (600 MW) Associated with the PG&E Capacity and Energy Transfer Agreement

Q. Please describe the 600 MW of BPA contracts associated with the PG&E Capacity and Energy Transfer Agreement.

A. The 600 MW of BPA transmission contracts provide bi-directional transmission from PSE's system to BPA's John Day Substation. The contracts were scheduled to expire August 1, 2019. PSE uses 300 MW of transmission to wheel power from the PSE system to the John Day Substation during summer months for delivery to Pacific Gas & Electric ("PG&E") at the California Oregon Border ("COB") per the terms and conditions of the PG&E Capacity and Energy Transfer Agreement. PSE uses 300 MW of transmission to wheel power from John Day to the PSE system during winter months for delivery from PG&E.

Q. Please summarize PSE's approach to evaluating the 600 MW of BPA contracts.

A. The BPA transmission contracts serve to meet PSE's obligation under the PG&E Capacity and Energy Transfer Agreement, which requires a five-year termination notice by either party. As a result, this transmission is necessary to fulfill PSE's continued obligations under the PG&E Capacity and Energy Transfer Agreement.

Q. Was PSE's EMC informed of the renewal of the 600 MW of transmission related to meeting the PG&E Exchange Agreement obligation?

A. Yes. The EMC was informed of the renewal of 600 MW of transmission to serve the PG&E Exchange Agreement on May 24, 2018. The Seventh Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-8, presents the slides that were presented to the EMC supporting these transmission contracts.

4. Summary of Transmission Contract Renewals and Additions

Q. Was PSE's renewal and acquisition of BPA transmission capacity a valuable and reasonable business decision?

A. Yes. As noted above, PSE relies on existing BPA transmission contracts from Mid-C to PSE's system to meet its capacity need in that PSE may use this transmission to wheel short-term market power from Mid-C to PSE's load. In this regard, these types of transmission contracts are akin to a resource for PSE and provide needed capacity. Additionally, firm transmission is required for PSE's generation resources and contracts in order to ensure reliable delivery to PSE's system to serve load. In all cases, PSE performed a full and detailed justification for the prudence of the costs of renewing and acquiring these BPA transmission contracts.

Q. What does PSE request from the Commission regarding PSE's renewal of transmission contracts?

A. PSE respectfully requests the Commission deem these contracts and expenses to be prudently incurred and allow PSE to fully recover these costs in rates.

Specifically, PSE requests the Commission approve the rate year transmission costs presented in Table 5.

Table 5. PSE Rate Year BPA Transmission Contracts Renewal and Additions Costs

Resource	Rate Year Power Cost ($000)
Mid-C Wells 266 MW	$5,905
Mid-C 624 MW	$13,853
Mid-C 150 MW (New)	$3,330
Colstrip 663 MW	$20,017
Goldendale 21 MW	$466
Goldendale 6 MW	$133
Clymer Substation (Load) 5 MW	$111
PG&E Exchange Agreement 600 MW	$13,320
Total	**$57,135**

B. New and Potential New Transmission for Existing Generation Facilities

Q. Did PSE acquire new BPA transmission contracts to wheel power from existing resources?

A. Yes. PSE acquired two new firm transmission contracts for wheeling power from existing resources, the Hopkins Ridge Wind Facility and the Lower Snake River

Wind Facility, starting in 2024. The BPA transmission contracts are listed in Table 6 and described below.

Table 6. BPA New Generation Transmission Contracts (Hopkins Ridge and Lower Snake River Wind Facilities)

Resource	Assigned Reference No.	Renewal Deadline	Start Date	Megawatt Capacity
LSR (Central Ferry)	82996227	New	3/1/2024	79
LSR	82996217	New	3/1/2024	75
Total				**154**

Q. Please describe the 75 MW and 79 MW contracts associated with the Hopkins Ridge and the Lower Snake River Wind Facilities, respectively.

A. In June of 2016 PSE submitted a request for 150 MW of transmission capacity from BPA in order to replace 150 MW of transmission for the Hopkins Ridge Wind Facility that will expire on March 1, 2024, and does not have roll-over rights. Along with requesting 150 MW at the Hopkins Ridge Wind Facility, PSE also requested 154 MW from the Lower Snake River Wind Facility as a contingency in case transmission was not available from the Hopkins Ridge Wind Facility. The contingency would give PSE the option to build a tie-line from the Hopkins Ridge Wind Facility to the Lower Snake River Wind Facility to wheel power from the Hopkins Ridge Wind Facility to the Lower Snake River Wind Facility and onto BPA's system. BPA granted 75 MW from the Hopkins Wind Facility and 79 MW from the Lower Snake River Wind Facility. PSE decided to accept both contracts because (i) BPA granted 75 MW of transmission for the Hopkins Ridge Wind Facility and (ii) the transmission from the Lower Snake

River Wind Faciltiy was still needed as a contingency in case the remaining transmission from the Hopkins Ridge Wind Facility was not granted. In addition, if the transmission from the Lower Snake River Wind Facility were not needed in the future for the Hopkins Ridge Wind Facility, the transmission will still have value for PSE via redirects to Mid-C for winter peaking capacity, for a new renewable resource, or for delivery from a potential expansion of the Lower Snake River Wind Facility.

Q. How did PSE evaluate the 75 MW and 79 MW transmission contracts?

A. In March 2018 PSE used PSM III to evaluate the impact of allowing the BPA transmission required to serve the Hopkins Ridge Wind Facility to expire. PSE compared ongoing operations with the renewed transmission to the premature shutdown of the Hopkins Ridge Wind Facility in 2024 as a result of not renewing the transmission. Without the required transmission, output from the Hopkins Ridge Wind Facility would be stranded, and PSE would need a replacement renewable resource to replace the lost output. The analysis indicated that renewing the transmission was a lower cost alternative to acquiring a replacement renewable resource, which would cost approximately $70 million.

Q. Were the transmission contracts for the 75 MW and 79 MW at the Hopkins Ridge and Lower Snake River Wind Facilities, respectively, approved by PSE's EMC?

A. Yes. The EMC approved the 75 MW and 79 MW transmission contracts from the Hopkins Ridge and Lower Snake River Wind Facilities, respectively, on March 22, 2018. The Eighth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-9, presents the slides that were presented to the EMC supporting these transmission contracts.

Q. Are transmission contracts for the 75 MW and 79 MW at the Hopkins Ridge and Lower Snake River Wind Facilities included in rate year power costs in this proceeding?

A. No. Costs of the transmission contract for the Hopkins Ridge and Lower Snake River Wind Facilties are not in rate year power costs because the contracts have an effective date of March 1, 2024. PSE is seeking a prudence determination for these contracts at this time rather than waiting for a future proceeding.

Q. What does PSE request from the Commission regarding PSE's potential new transmission contracts for existing generation facilities?

A. PSE respectfully requests the Commission deem these contracts and expenses to be prudently incurred and allow PSE to fully recover these costs in rates.

IV. NEW RESOURCES

Q. Does PSE seek prudence determination for any new resources that impact power costs in the rate year?

A. Yes, PSE seeks a prudence determination for a new slice of the Wells Hydroelectric Project. On June 4, 2018, PSE executed a transaction with Douglas PUD on behalf of the Confederated Tribes of the Colville Reservation to acquire the Colville slice of the Wells Hydroelectric Project. The hydro slice represents a 5.5 percent share of the output of the Wells Hydroelectric Project, including 42.5 MW of electrical generating capacity and 370 MWh of pond storage capacity. The term of the contract is three years plus one month, from September 1, 2018, through September 30, 2021. Douglas PUD offered the slice in a competitive auction and PSE was the successful bidder. This product provides PSE with energy and system flexibility to further enhance its least cost energy portfolio.

Q. Does the Colville slice of the Wells Hydroelectric Project provide additional capacity to PSE?

A. No. The Colville slice of the Wells Hydroelectric Project does not provide PSE with additional capacity because (i) the energy will be wheeled to PSE's system using existing Mid-C transmission capacity and (ii) Mid-C transmission capacity is treated as a resource in PSE's IRP. The 2017 IRP showed a resource capacity need beginning in 2023, and due to the term of the Colville slice it did not provide a benefit in avoiding or shifting out potential resource builds. However, the slice still provides benefits to PSE's customers.

Q. Describe PSE's approach to analyzing the Colville slice of the Wells Hydroelectric Project.

A. PSE estimated the value of the Colville slice of the Wells Hydroelectric Project based [redacted].

[redacted].

The Colville slice of the Wells Hydroelectric Project also provides value in the form of [redacted].

[redacted]. To assign a value to the [redacted], PSE assumed that the energy from the Colville slice of the Wells Hydroelectric Project [redacted]. [redacted]. [redacted]. [redacted]. [redacted].

Please see the Ninth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-10C, for a description of the analysis used to estimate the value of the Colville slice of the Wells Hydroelectric Project.

Q. What alternatives did PSE consider in acquiring the Colville slice of the Wells Hydroelectric Project?

A. This acquisition of the Colville slice of the Wells Hydroelectric Project resulted from a competitive bidding process initiated by Douglas PUD. PSE had no additional hydroelectric capacity alternatives at the time of the transaction. As an alternative to the energy benefits from the Colville slice of the Wells Hydroelectric Project, PSE considered purchasing peak and off-peak power in the forward Mid-C market. PSE projected the cost of peak and off-peak Mid-C power purchases from financial price marks that PSE receives from a third-party market provider. Forward power purchases are fixed volumes that PSE agrees to buy over a standard set of hours (e.g. peak hours represent hour ending 7:00 through hour ending 22:00). These "block energy purchases" cannot be shaped hour-by-hour to balance to load net of variable resources or to optimize to real-time energy prices. The flexibility of the Colville slice of the Wells Project relative to block market purchases and the benefit of power from a specified zero emissions source versus market purchases from an unspecified source were advantageous relative to the alternative of block market purchases.

Q. Was acquisition of the slice approved by the EMC?

A. Yes. PSE's EMC approved a price of $[redacted] million (approximately $[redacted]/MWh), which was accepted by Douglas PUD.

V. NATURAL GAS RESOURCES

A. Overview of Gas Transportation

Q. Please describe the gas resources held by PSE for power generation.

A. PSE maintains a diverse portfolio of firm pipeline capacity and firm storage capacity to provide reliable fuel supply to the generation fleet. The capacity currently held will meet (i) 100 percent of PSE's combined-cycle combustion turbine requirements on a year-round basis, (ii) approximately one-half of the winter-time requirements of its simple-cycle combustion turbines, and (iii) approximately one-third of the summer-time requirements of its simple-cycle combustion turbines.

PSE also holds firm transportation capacity upstream of the two major pipeline interconnects at Sumas, Washington, and Stanfield, Oregon, to ensure the availability and access to supply at those points and to diversify the pricing of the supply. Such upstream capacity is equivalent to approximately 50 percent of PSE's requirements at those points. For generating facilities situated on the distribution system of Cascade Natural Gas Company ("Cascade Natural Gas"), PSE has reserved the necessary firm distribution service to ensure reliable deliveries of fuel acquired upstream.

PSE has contracted for firm storage service to provide reliability, flexibility, and, in conjunction with special firm storage redelivery service, incremental supply to the generation fleet in the winter months. The storage service provides necessary reliability and flexibility to start or stop generation as needed during the gas day by providing an immediate supply of fuel or a place to store the gas and avoid a pipeline imbalance. The storage also serves as an integral part of the portfolio to allow incremental deliveries in winter months because it is coupled with winter-only pipeline capacity. PSE's storage service capacity can also serve as an alternate supply source to avoid extreme pricing deviations at either of the major supply points.

Tables 7 and 8 below detail the firm natural gas resources held by PSE to serve its generation fleet.

Table 7. Natural Gas Resources for PSE Gas-Fired Generators Firm Pipeline Capacity

Pipeline	Path	Capacity (Dth/d)		Annual (1) Demand Cost ($000)
Northwest Pipeline	Sumas to plants	108,957		$15,523
Northwest Pipeline	Stanfield or Plymouth to plants	78,928		$11,245
Northwest Pipeline	Plymouth or Stanfield to plants	15,000		$557
Total NWP Annual		202,885	(2)	$27,325
NWP-Winter Only	Jackson Prairie to plants	34,197	(2)	$1,209
Total NWP-Winter		237,082		$28,535
Cascade Natural Gas	Sumas to Whitehorn	24,000	(2)	$147
Cascade Natural Gas	Sumas to Ferndale	52,000	(2)	$985
Cascade Natural Gas	NWP to Encogen	37,000		$204
Cascade Natural Gas	NWP to Fredonia	94,000		$1,527
Cascade Natural Gas	NWP to Mint Farm	52,000		$833
Northwest Pipeline	Goldendale Lateral	52,000		$129
Puget Sound Energy	Sumas Pipeline	26,000	(2)	–
Westcoast Energy	Station 2 to Sumas	88,352		$13,988
Nova Gas Transmission	NIT to A/BC	41,420		$2,299
Foothills Pipeline	A/BC to Kingsgate	40,946		$1,162
Gas Transmission NW	Kingsgate to Stanfield	40,567		$2,064
Total Capacity to plants	Annual	304,885		
	Winter	339,082		
Total Pipeline Demand Charges				$51,874

Notes:
(1) Costs for the Rate Year: May 1, 2020 through April 30, 2021
(2) Capacity included in Total Capacity to plants

There is only one minor change to the volumes presented in Table 7 since the 2017 GRC. This change reflects slightly higher volumes on the Westcoast Energy pipeline.

Table 8. Natural Gas Resources for PSE Gas-Fired Generators
Firm Storage Service Capacity

Project	Withdrawal Capacity (Dth/d)	Storage Capacity (Dth)	Annual (1) Demand Cost ($000)
NWP Plymouth LNG	70,500	241,700	$958
NWP Jackson Prairie	6,704	140,622	$67
Jackson Prairie Storage Project (interbook)	50,000	500,000	$980
Total Storage Service	127,204	882,322	
Total Storage Demand Charges			$2,005
Total Gas Resource Demand Charge			**$53,879**

Notes:
(1) Costs for the Rate Year: May 1, 2020 through April 30, 2021
(2) Withdrawal capacity is subject to recall

B. Renewed Resources

Q. Please describe changes to the gas pipeline and storage resources that have taken place since the 2017 GRC.

A. PSE has not acquired any new resources since rates were set in the 2017 GRC. PSE has only extended the terms of Westcoast Energy firm transportation contracts and the Jackson Prairie interbook storage agreement. In addition, rates charged by the various pipelines have changed as a result of rate case settlements.

Q. Please identify the extended Westcoast Energy pipeline contracts and other changes to the Westcoast Energy contracts.

A. PSE holds approximately 88,000 Dth/day of firm capacity on Westcoast Energy from Station 2 in the Northeast British Columbia production zone to the Huntingdon/Sumas hub at the Canada/US border. PSE acquired this capacity in an amount equal to approximately 50 percent of peak day need at Sumas in order to ensure reliability of supply and to obtain pricing diversity. PSE generally maintains contract terms of three to five years for this capacity to take advantage of term-differentiated rates offered by the pipeline. Westcoast Energy's tariff provides for a standard contract term of two years in order to receive renewal rights and then provides a 3 percent rate reduction for contract terms of three years and a 5 percent rate reduction for contract terms of five years or more. Contract renewals must be made a minimum of 13 months before the current term expiration.

In October 2016, PSE extended the term of approximately 33,000 Dth/day of firm capacity from November 30, 2017 to November 30, 2020. PSE chose to extend for only three years to allow greater flexibility by staggering termination dates on the various Westcoast Energy contracts for both gas and power portfolios. In September 2017, PSE extended the term of approximately 51,000 Dth/day of firm capacity from October 31, 2018 to October 31, 2023.

In addition, Westcoast Energy revised the heat content conversion factor on all of its contracts (which are stated in volumetric measurement of cubic meters) to reflect the sustained higher British thermal unit (BTU) content of gas connected to the system. On November 1, 2017 the conversion was increased from 1.046 BTU per cubic foot to 1.074 BTU per cubic foot. As a result, PSE's total Westcoast Energy pipeline capacity increased from 86,143 Dth/day in the previous rate case to 88,352 Dth/day currently.

Q. Please identify the analyses performed by PSE prior to extending the Westcoast Energy contracts.

A. PSE compared the fixed costs of the pipeline contract to a modeled optimization of the pipeline capacity. The fixed costs and optimization value were netted and discounted at PSE's weighted average cost of capital. PSE also considered the qualitative factors of increased reliability and supply basin diversity.

Prior to extending the Westcoast Energy contracts, PSE considered both the need for and value of the term extensions. There are no alternative upstream pipelines, so the only viable alternative is to not extend the agreements and rely exclusively on the Huntingdon/Sumas market for approximately 50 percent of PSE gas-fired generation fuel needs. Historically, pricing at the Huntingdon/Sumas market hub has been volatile during periods of cold weather or pipeline disruptions.

In considering the three-year extension of 33,000 Dth/day from November 2017, PSE estimated the value of the capacity to range from a manageable net cost to a material net benefit, based on forecast demand charges and historical and forecast differentials between Station 2 and Huntingdon/Sumas pricing. PSE determined the value of reliable supply access in a tighter Sumas supply market outweighed the potential net present value cost of the capacity and therefore extended the agreements.

In considering the five-year extension of 52,000 Dth/day from November 2018, PSE estimated the net present value of the capacity to be a manageable cost based on forecast demand charges and forecast differentials. PSE determined the value of supply access in a tighter Sumas supply market outweighed the potential net present value cost of the capacity and therefore extended the agreements.

Q. Were the Westcoast Energy contract extensions approved by the EMC?

A. Yes. The EMC approved the 33,000 Dth/day extension in October 2016 and the 52,000 Dth/day extension in September 2017. Please see the Tenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-11C for the EMC slides related to the 33,000 Dth/day extension, and the Eleventh Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-12C for the EMC slides related to the 52,000 Dth/day extension.

Q. Please identify the extended storage contracts and analysis performed to support such extensions.

A. PSE's power book contracts for the use of some of PSE's firm capacity in the Jackson Prairie Storage Project from the gas book. The current internal "inter-book" contract became effective on April 1, 2016 and was described in detail in the 2017 GRC. The agreement runs indefinitely, but requires a revaluation of the value of the storage made available by PSE's gas book every three years, to ensure a reasonable and appropriate transfer price between the two portfolios.

PSE determined that modifications to the terms of the agreement were necessary to accommodate a range of pipeline and storage facility conditions. PSE performed a revaluation of the storage capacity and assigned a new annual value of $[redacted] to the contract, effective April 1, 2019, replacing the previous transfer price of $[redacted] per year. The agreement remains a key to efficient management of gas supplies used in power generation.

C. Pipeline Capacity Costs

Q. What pipeline rates are reflected in rate year power costs?

A. Rates in effect as of March 2019 are reflected in power costs. Northwest Pipeline's current rates were effective October 1, 2018, and are expected to remain in place through the end of 2022. An interim rate increase on Westcoast Energy became effective on January 1, 2019, with a permanent update expected in April 2019, after proposed power costs for this proceeding were complete.

If rate adjustments are approved by the appropriate regulatory authorities during the pendency of this case, PSE will include adjustments to the pipeline rates and related gas costs when power costs are updated.

VI. ENERGY IMBALANCE MARKET

Q. What is the Energy Imbalance Market?

A. The EIM is a voluntary, within-hour energy market that provides Balancing Authorities another tool to reliably and economically maintain balance between electric demand (load) and supply (generating resources). It is operated by a central market operator who optimizes the generation resources of the Balancing Authorities within the EIM footprint every fifteen and five minutes. The California Independent System Operator ("CAISO") serves as the market operator for the EIM in which PSE operates. Historically, energy has been predominately traded among entities through bilateral transactions of hourly energy products. Within the hour there has been no liquid market for energy, and Balancing Authorities had to rely on their own generating resources to continuously match imbalances in load and non-dispatchable generation. The EIM provides a sub-hourly market that enables Balancing Authorities to transact and utilize lower-cost resources in other Balancing Authorities to balance load and resources.

Q. What costs related to the EIM are included in rate year power costs?

A. There are no explicit EIM related costs included in PSE's proposed rate year power costs. Actual costs for the test year ended December 2018 were $3.4 million in FERC Account 557, Other Expenses. PSE will incur costs during the rate year, but no amount is included in proposed rate year power costs. This is consistent with the treatment of EIM fixed costs, as discussed in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T.

Q. Why are EIM costs excluded from proposed rate year power costs?

A. Exclusion of these costs is consistent with rates currently in place, which were established by the 2017 GRC Settlement.

Q. How did the 2017 GRC Settlement treat EIM costs?

A. The treatment of EIM costs agreed to in the 2017 GRC Settlement was proposed by Kyle Frankiewich, witness for Commission Staff. The capital costs were excluded from rate base and the operating costs were excluded from rate year power costs. The pro forma total annual costs identified in the 2017 GRC, including depreciation, return on rate base, and operating costs were included in allowed costs in the Power Cost Adjustment ("PCA") mechanism even though they are not included in the baseline rate. This has the effect of increasing under-recoveries and decreasing over-recoveries of power costs. The first $17 million of over- and under-recoveries is assigned to PSE, and amounts beyond $17 million are shared between PSE and customers based on sharing bands defined in the PCA mechanism.

Q. Does PSE include any benefits of EIM participation in rate year power costs?

A. No. PSE did not include a discrete reduction to power costs based on the estimated benefits of EIM participation for three reasons. First, the 2017 GRC Settlement excluded both costs and benefits from power costs, so exclusion is consistent with current treatment. If costs are excluded, benefits should be excluded. Second, EIM benefits are, by definition, theoretical in nature and difficult to quantify to the standards required for inclusion in rates. Available benefits estimates are backward-looking and based on a counterfactual scenario, which is an estimate of how market participants would have operated in the absence of the EIM. Producing a forward estimate of benefits would require reliance on significant assumptions, massive datasets, a WECC-wide study footprint, and multiple EIM market optimization timelines. Third, the AURORA results already reflect some benefits of inter-regional transactions because the AURORA model PSE uses to project rate year power costs perfectly optimizes all of the resources in the West and allows for transfers between Balancing Authorities subject to transmission constraints. Therefore, a counterfactual model that forms the basis of estimated benefits is not directly comparable to the AURORA output used to estimate rate year power costs, and benefits cannot simply be subtracted from AURORA output to calculate net power costs.

VII. PROJECTED RATE YEAR POWER COSTS

A. Overview of Power Costs

Q. Please quantify PSE's net power cost projection for this proceeding.

A. As shown in Table 9 below, PSE's projected rate year net power costs are $743.5 million.

Table 9. Projected Rate Year Power Costs
($ in millions)

AURORA	$487.3
Costs Not in AURORA	$256.2
Projected Rate Year Power Costs	$743.5

Please see the Second Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-3C, for PSE's projected rate year net power costs. Please see the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, for the adjustment of PSE's projected rate year power costs to test year levels. Please see the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-1CT, for PSE's projected rate year production operations and maintenance costs.

B. Methodology

Q. How did PSE estimate rate year power costs in this proceeding?

A. As in prior cases, PSE used the AURORA hourly dispatch model to project a portion of its net power costs for the rate year. PSE calculated the remaining rate year power costs outside of the AURORA model and has referred to these power costs as "Costs Not in AURORA."

Q. What costs are projected using the AURORA model?

A. In the power costs analysis, AURORA produces a forecast of regional power prices and the dispatch of PSE's generating units. The variable costs of fuel for PSE's resources, certain long-term power purchase agreements, and other market purchases and sales are estimated by AURORA and included in rate year power costs. Other power costs, such as transmission costs, fixed gas transportation costs and fixed costs associated with Mid-C hydroelectric projects, are calculated outside of AURORA.

Please see the Twelfth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-13C, for a summary of rate year power costs by resource. Please see the Thirteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-14C, for a monthly detail of costs and energy produced by AURORA in comparison to similar output from the 2017 GRC Settlement. Please see the Fourteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-15C, for a summary of the rate year Costs Not in AURORA. Please see the Fifteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-16C, for input data on the resources used in AURORA.

Q. Were there changes made to the AURORA hourly dispatch model since the 2017 GRC?

A. Yes. Energy Exemplar, the developer of the AURORA hourly dispatch model, provides periodic software and database updates. The software version of AURORA used in this filing is Version 13.1.1001, which Energy Exemplar released in May 2018. The database used is the Zonal US_Canada Data Package 2019_v1 ("2019 Database"), which Energy Exemplar issued in March 2019. Energy Exemplar updated the resource, demand, financial, and regional data within the 2019 Database to reflect more recent data, information and economic conditions than those included in the AURORA database used in the 2017 GRC.

C. Updates to Power Costs Methodology

Q. Did PSE make changes to its approach to estimating power costs since the 2017 GRC Settlement?

A. Yes, PSE made some enhancements to its approach to estimating power costs since the 2017 GRC Settlement. These changes build upon the established methodology and use the same tools, AURORA and MS Excel spreadsheets, to estimate power costs. However, PSE has not changed the following:

1. Use of the AURORA model and database for the costs and characteristics of all resources, fuels, loads and transmission in the Western Interconnection, with updates of natural gas prices, load, and resource characteristics of PSE resources;

2. Use of three-month average natural gas prices as an input to AURORA;

3. Use of power prices generated by AURORA by modeling the Western Interconnection;

4. Assumption of 80 years of hydroelectric energy; and

5. Methods for calculating major Costs Not in Aurora, such as transmission costs, gas transportation costs and fixed costs of Colstrip and Mid-C contracts.

Q. What changes did PSE make to its power cost methodology?

A. In prior proceedings, the variable costs of fuel for PSE's resources, certain long-term power purchase agreements, and other market purchases and sales were estimated by AURORA by modeling the Western Interconnection. In the proposed approach, the Western Interconnection is still run in AURORA, and the market prices generated by that run are input into a second AURORA run. This second run utilizes a two-zone model, with the market being the first zone and PSE's system being the second zone. In this two-zone run, PSE resources are dispatched to meet PSE load. Using this two-zone model allows use of AURORA functionality for estimating certain costs that in the past have been calculated outside the model. The costs now included in AURORA are contingency reserves and the costs related to balancing load with wind and other resources every hour.

Q. What are the benefits of using the two-zone model?

A. AURORA's ancillary services functionality can be utilized to estimate the costs of contingency reserves and the costs related to balancing load with wind and other resources every hour. Computational time requirements would be excessive if this functionality were used when modeling the entire Western Interconnection. In prior proceedings, PSE has estimated these costs using its Hour Ahead Balancing Model, an MS Excel-based model that uses AURORA output. This model produces reasonable results, but it is cumbersome and time consuming to use. Calculating these costs in AURORA is a more efficient and streamlined process.

Another benefit of the two-zone approach is that impacts of changes to PSE inputs on model results can be evaluated without re-running the Western Interconnection model.

D. Major Assumptions

1. Rate Year Power Supply Resources

Q. Is PSE's rate year power supply portfolio for this proceeding different from the pro forma power cost portfolio approved in the 2017 GRC?

A. Yes. Changes to PSE's power supply portfolio have occurred or will occur by or during the rate year. Specifically, the underlying portfolio used to determine PSE's rate year power costs for this proceeding reflect the following:

(i) the addition of the 5.5 percent Colville slice of the Wells Hydroelectric Project, described earlier in this testimony;

(ii) closure of Colstrip Units 1 and 2 after December 31, 2019, which is before the rate year in this proceeding;

(iii) inclusion of a full year of costs related to a renewed power purchase agreement with Douglas PUD for power from the Wells Hydroelectric Project, effective September 1, 2018;[5]

(iv) contracts executed under PSE's Schedule 91 Tariff, "Cogeneration and Small Power Production";

(v) new transmission contracts discussed earlier in this testimony;

(vi) addition of the Skookumchuck PPA for 136.8 MW beginning January 1, 2020 to serve Green Direct customers;

(vii) addition of the Lund Hill PPA for 150 MW beginning January 1, 2021 to serve Green Direct customers; and

[5] Because the renewed contract was effective in the last four months of the rate year in the 2017 GRC, only four months of costs were included in current rates.

(viii) updates to all rate year power contracts and resources to reflect current operations, contract terms and planned maintenance.

2. Operating and Maintenance Costs of Gas-Fired Resources

Q. Are operating and maintenance costs included in power costs?

A. No. Operations and maintenance ("O&M") costs are not included in power costs. When Energy Supply Merchant department employees make daily economic decisions of how to provide the lowest cost power for customers, they compare the variable cost of running resources with purchasing power on the market. The cost of running a resource includes fuel and variable O&M costs, because those costs will be incurred if the resource is run. Modeling of those economic dispatch decisions requires including variable O&M when considering the choice between running a resource and purchasing power, consistent with operations. However, O&M costs are not included in power costs operationally or in rate year power costs proposed in this proceeding.

Q. Have the variable O&M costs used to model the dispatch of gas-fired resources changed since the 2017 GRC Settlement?

A. Yes. Variable O&M costs used to model the dispatch of gas-fired resources changed since the 2017 GRC Settlement. In 2018, PSE undertook a comprehensive review of its O&M costs. In this process PSE:

1. Clearly defined all types of operating and maintenance costs;

2. Identified those costs that are variable (i.e, they change based on operation of the resources);

3. Compiled three years of historical data for each of PSE's resources;

4. Calculated three-year rolling averages of variable O&M costs based on historical data;

5. Established processes for updating the three-year rolling average on a quarterly basis and for approving and implementing the costs in daily operations; and

6. Implemented the new process for updating, approving, and utilizing the costs in daily operations.

Please see the Sixteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-17C, for a summary of the 2018 review of variable O&M costs.

Q. What costs are included in PSE's definition of variable O&M costs?

A. Variable operating costs are costs incurred on production facilities outside of normal stand-by conditions to operate production facilities including when a plant is being prepared to start, starting up, increasing or decreasing output, in steady state operation, shutting down, or being secured after shutdown until normal stand-by conditions are achieved. They include costs associated with:

1. Raw water consumption;

2. Boiler chemicals;

3. Emission control system chemicals (e.g., ammonia);

4. Cooling tower chemicals;

5. Variable lease fees;

6. Variable license fees (if any);

7. Variable O&M supplier contract fees;

8. Purchased station service power in excess of offline consumption (for Goldendale Generating Station only, because the Goldendale Generating Station's station power is purchased rather than generated by the plant); and

9. Labor for simple-cycle CT operations, if outside of normal work hours.

Variable maintenance costs are incurred on production facilities for restoration of plant performance or function, including maintenance, repair, or replacements due to degradation resulting from incremental use. They include costs associated with:

1. Predictive maintenance,[6] which is work performed based on inspection results or predictive monitoring findings to reduce the likelihood of failure;

2. Corrective maintenance, which is work performed to restore performance or function after a failure;

3. Variable O&M service contract fees; and

4. Overtime labor related to corrective maintenance events.

Fixed O&M costs, maintenance activities performed on a calendar basis (including preventive maintenance and predictive monitoring of equipment), and capital costs are all excluded from variable O&M costs. Major maintenance, as defined by the requirements of Order 6 in Docket UE-130617, is not included in the variable O&M costs described above but is included in the AURORA dispatch logic.

[6] Predictive maintenance activities result from predictive monitoring, inspections, or testing.

Q. How do the updated costs compare with those used in the 2017 GRC Settlement and prior proceedings?

A. Variable O&M used in the 2017 GRC Settlement had been calculated using historical data for the three year period 2013-2015. Those estimates had been developed prior to the more comprehensive study that was done in 2018. In Docket UE-141141 (the "2014 PCORC"), PSE included only variable operating costs in its AURORA modeling. Table 10 presents the variable O&M costs for gas-fired resources used in the 2017 GRC Settlement and the variable O&M costs proposed in this proceeding.

Please see the Seventeenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-18C, for the Plant Variable Operations and Maintenance Cost Update version that contains the O&M costs used in the AURORA dispatch logic in this proceeding.

Q. Does PSE also include major maintenance costs in its dispatch logic when calculating rate year power costs in this proceeding?

A. Yes. PSE also included major maintenance costs in its dispatch logic when calculating rate year power costs in this proceeding. As with variable O&M, major maintenance is not a power cost and is not included in rate year power costs. The timing, frequency, and magnitude of major maintenance events are all influenced by the run time of the resource.

For projecting power costs in this proceeding, major maintenance costs for simple cycle combustion turbines were modeled on a cost per start basis. For combined cycle combustion turbines, major maintenance costs were developed on a cost per hour of run time basis and modeled in AURORA on a cost per MWh basis.

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.

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.

Operationally, major maintenance events are considered in PSE's daily dispatch decisions. Therefore, they need to be included in the modeling of dispatch decisions for projecting power costs.

Q. What major maintenance costs were used to model power costs in this proceeding?

A. For modeling rate year power costs the major maintenance costs are the same as those used in operational dispatch decisions. The costs included in Table 10 below were developed by PSE in accordance with CAISO's methodology for EIM participants.

Table 10. Variable O&M and Major Maintenance Costs of Gas-Fired Resources

Resource	2017 GRC Settlement Variable O&M ($/MWh)	2019 GRC Variable O&M ($/MWh)	2019 GRC Major Maintenance
<u>**Combined-Cycle Combustion Turbines**</u>			
Encogen	$[redacted]	$[redacted]	$[redacted] / MWh
Sumas	$[redacted]	$[redacted]	$[redacted] / MWh
Ferndale	$[redacted]	$[redacted]	$[redacted] / MWh
Mint Farm	$[redacted]	$[redacted]	$[redacted] / MWh
Goldendale	$[redacted]	$[redacted]	$[redacted] / MWh
<u>**Simple-Cycle Combustion Turbines**</u>			
Whitehorn 2&3	$[redacted]	$[redacted]	$[redacted] / start
Frederickson 1&2	$[redacted]	$[redacted]	$[redacted] / start
Fredonia 1&2	$[redacted]	$[redacted]	$[redacted] / start
Fredonia 3&4	$[redacted]	$[redacted]	$[redacted] / start

Frederickson 1 combined cycle variable O&M of $[redacted]/MWh is based on PSE's contract with the majority owner, Atlantic Power.

3. Projected Hydro Availability

Q. What historical streamflow record did PSE use in its net power cost projection in this proceeding?

A. PSE used the average of the 80-year Mid-C streamflow history from 1929 through 2008 to project power costs for the rate year, consistent with the data used in the 2017 GRC. In the 2014 PCORC, Docket UE-130617 (the "2013 PCORC"), and Dockets UE-111048 & UG-111049 (the "2011 GRC"), PSE used 70-year Mid-C streamflow history from 1929 through 1998. In the 2017 GRC, PSE changed to 80-year data in consideration of the Commission's Order 11 in Dockets UE-090704 & UG-090705,[7] which noted that future rate cases should include more recent hydro data.[8] It is of interest to note that the Commission stated in the 2009 GRC Order:

> Inasmuch as the Company has access to at least some of the more recent data, its power cost evidence in future rate proceedings should include consideration of that data. . . .
>
> . . . . However, we have stated above our preference for using the longest span of years possible.

To be consistent with the Mid-C historical data, PSE used the same 80-year historical west side streamflow records for projections related to PSE's owned hydropower on the west side of the Cascade Mountains.

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7 *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 & UG-090705, Order 11 (Apr. 2, 2010) (the "2009 GRC Final Order").

8 *See id.* at ¶ 124.

Q. Did PSE make changes to its assumption of 80-year hydro?

A. PSE made an adjustment to its application of 80 years of hydroelectric data to power costs. As indicated above, power costs continue to be projected using estimates of 80 years worth of hydroelectric generation, which are based on 80 years of actual streamflow data. Historically, PSE interpreted this requirement by running AURORA 80 times, one for each year of hydro generation, and taking the average of power costs that resulted from these 80 runs. This is a time consuming process that requires significant computational power.

In this proceeding PSE proposes to modify its interpretation of 80-year hydro to averaging the input to AURORA, running the model once using that average hydro as an input, and using the power costs that result from that run rather than averaging the output of 80 runs.

Q. How much time is saved by doing a single AURORA run with 80-year hydro as an input instead of doing 80 runs and taking the average output?

A. On average, it takes about 14 hours of computational time for AURORA to complete 80 runs, or about 11 minutes per run, on a desktop machine devoted to AURORA. These 80 runs produce a large volume of hourly output that has to be manually extracted and processed by an analyst to calculate power costs. Reducing the number of AURORA runs not only reduces the computational time, it reduces the manual labor required to extract and process the output data. The power of the computing resources used impacts both computational time and the analyst's efficiency in processing the output data.

Q. What is the difference in power costs between the average of 80 runs and a single run using the average of 80 years of hydro?

A. Examination of the AURORA results used to set final rates in the last three proceedings and PSE's proposed power costs in this proceeding indicates that AURORA output from a single run ranged from 0.04 percent below to 1.30 percent above results based on 70 or 80 runs.[9] In the current proceeding, PSE's proposed AURORA results, which are only a portion of total power costs, are 1.30 percent higher than they would be using 80 AURORA runs. On average, AURORA output from a single run is 0.50 percent above average output from 70 or 80 runs. Table 11 presents the difference in results between a single run and the average results from 70 or 80 runs from the current proceeding and the last three proceedings.

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9 Prior to the 2017 GRC, 70 years of hydro data were used. In the 2017 GRC PSE updated hydro to 80 years of data because it had become available.

Table 11. Comparison of Aurora Results Using a Single Run or 70/80 Runs (dollars in thousands)

Proceeding	Single Run Results	Average of Results from 70/80 Runs	Difference (Single Run – Average)	Difference (Percent of Average)
2014 PCORC Settlement	$501,209	$501,674	$(465)	-0.09%
2016 Power Cost Update	$475,587	$475,790	$(203)	-0.04%
2017 GRC Settlement	$457,344	$453,329	$4,015	0.89%
2019 GRC Proposed	$487,336	$481,087	$6,249	1.30%
Average	**$480,369**	**$477,970**	**$2,399**	**0.50%**

PSE proposes to estimate rate year power costs based on a single AURORA run that uses the average of 80 years of hydro generation data as an input. The computational and analytical time required to generate 80 AURORA runs and process the output is excessive given the relatively small differences in results.

4. Natural Gas Prices

Q. What natural gas prices did PSE use in running its AURORA hourly dispatch model for the rate year?

A. As the Commission noted in its final order in Dockets UE-060266 and UG-060267 (the "2006 GRC"), the update for gas costs is "well-established" and should be "straightforward, mechanical and non-controversial."[10] Consistent with this order and all rate cases since, PSE used a three-month average of daily forward market prices for the rate year for each trading day in the three-month

[10] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-060266 and UG-060267, Order No. 08 at ¶104 (Jan. 5, 2007).

period ending January 31, 2019. PSE input these data into the AURORA hourly dispatch model for each month of the rate year.

In addition, consistent with prior general rate cases, all previously executed rate year short term power and gas for power contracts at the price cut-off date, January 31, 2019, are included in the rate year power costs. Fixed-price short term rate year power contracts are included within the AURORA hourly dispatch model and fixed-price rate year contracts for natural gas for its power portfolio are adjusted outside of the AURORA hourly dispatch model in the “Costs Not in AURORA” calculations. An adjustment is also included in the “Costs Not in AURORA” calculation for premiums and discounts associated with any power and gas for power contracts priced at plus or minus index. These contracts require updating whenever natural gas prices are changed or updated during a proceeding.

Q. Please explain the fixed-price contracts mark-to-model adjustment.

A. The gas price input to the AURORA hourly dispatch model represents a three-month average of the forecast market rate year gas prices at a certain point in time (in this case, January 31, 2019). Given PSE’s hedging protocol, which includes a programmatic component that requires a specified amount of hedging be done each month, rate year power costs must reflect PSE’s actual fixed price gas for power and power rate year contracts as of that date. Hedges are included because forecast rate year power costs consist of two components: (i) costs related to actual commitments; and (ii) forecast market costs dependent upon the AURORA modeled operational and market fluctuations. The adjustment requires calculating the difference between the three-month average monthly price of natural gas at the pricing cut-off date (January 31, 2019, in this proceeding) and the actual price of natural gas hedges transacted for the rate year as of the same cut-off date.

For each month of the rate year, this difference is multiplied by the volume of the gas for power hedges transacted for the rate year. The resulting amount represents the "mark-to-model" that is included in the power cost forecast. Including the fixed-price power contracts within the AURORA hourly dispatch model and marking both the fixed-price gas for power and index-based power and gas for power contracts to the three-month average rate year gas price input in the "Costs Not in AURORA" calculation is consistent with the methodology used by PSE in determining rate year power costs since the 2006 GRC. This adjustment ensures that the cost included in rates represents what PSE expects to pay for those contracts PSE has already entered into.

Q. How do projected gas prices input into AURORA for this proceeding compare with those in the 2017 GRC Settlement?

A. Use of a single price can be misleading because there are different projected gas prices for each month of the rate year and for the different trading hubs from which PSE purchases gas. Additionally, these prices do not consider the impact of the fixed price gas contracts at the price cut off date, which may significantly change the average gas price. For purposes of comparison, however, the average forward gas price at the Sumas trading hub for the rate year is $2.06 per million British thermal units ("MMBtu") (for the three months ended January 31, 2019), which is $0.42 per MMBtu lower than the average $2.48 per MMBtu price included in the 2017 GRC Settlement, which was the basis for rates effective December 19, 2017. The average gas price reflected in the 2016 Power Cost Update was $2.76 per MMBtu (for the three months ended August 26, 2016, 2014). Table 12 below presents average rate year gas price comparisons.

Table 12. Average Annual Rate Year Gas Prices

Rate Case =>	2019 GRC	2017 GRC Settlement	2016 Power Cost Update
3-Mo Average at =>	1.31.19	6.23.17	8.26.16
Rate Year	May 2020 – April 2021	Jan 2018 – Dec 2018	Dec 2016- Nov 2017
Sumas	$2.06	$2.48	$2.76
Change from Prior	$(0.42)	$(0.28)	$(1.10)

Please see the Eighteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-19C, which presents monthly gas prices used in this analysis along with the AURORA-generated Mid-C power prices.

Q. Please explain the source of the gas price inputs.

A. Consistent with prior rate cases, PSE has used forward gas market price data supplied by Kiodex Global Market Data (“Kiodex”). PSE contracts with Kiodex for forward market price data for specific gas and power trading points and for the trading hubs that are input into AURORA.

Kiodex, however, does not offer forward price curves for the Station 2 hub located in British Columbia. Although this price hub is not a trading hub required for input to AURORA, PSE has T-south pipeline capacity between Station 2 and

Sumas under contract with Westcoast Energy, and a gas price at Station 2 is necessary for estimating gas supply costs. Since the AURORA model uses the input Sumas gas prices for PSE's gas fired generators' dispatch and power costs, PSE must separately consider the cost difference between Station 2 and Sumas in the "Costs Not in AURORA" adjustments.

Since there is no readily available forward gas price for Station 2, PSE has contracted with a third party (Wood Mackenzie) to provide an independent forecast of the cost difference, or basis, between the Henry Hub and Station 2 gas hubs. Basis is the cost difference between two different gas hubs and is represented as a positive or negative number representative of the price relationship between the two points. The forecast uses Henry Hub as the primary gas hub to measure basis, as it is the most liquid and transparent trading hub of natural gas.

PSE calculates the monthly Station 2 forward gas prices by applying the Wood Mackenzie basis forecast to Kiodex Henry Hub forward gas prices. In this regard, all gas prices used in the determination of rate year power costs are then based upon forward price curves and third party forecasts for the rate year. PSE has used third party forecasts of price differentials to estimate Station 2 prices since the 2011 GRC. In this proceeding PSE adjusted its application of the Wood Mackenzie forward price forecast. Wood Mackenzie provides basis forecasts between Henry Hub and both Sumas and Station 2. In the past, PSE took the relationship between those two basis differentials from Henry Hub to estimate a Station 2 price.

In this proceeding, PSE applied the Henry Hub to Station 2 basis directly to Kiodex forward Henry Hub prices to derive Station 2 prices, which is a more direct application of the third party forward price forecast provided by Wood Mackenzie. Referencing Station 2 to Henry Hub settlement is reasonable because Henry Hub prices are used as benchmarks across North America and at specific locations to price natural gas, setting a standard for pricing at less liquid gas hubs. Henry Hub has been used as a pricing reference for the NYMEX Henry Hub futures contract since 1990, reflecting the depth of transactions and price discovery at this location.

PSE is in the process of changing its source of forward market prices from Kiodex to Platts. When PSE updates power costs with new gas prices during the course of this proceeding, it will switch to using forward prices provided by Platts.

Q. Does PSE intend to update its projected power costs with updated gas price projections during this proceeding?

A. Yes. Consistent with prior rate proceedings, PSE intends to update its projected power costs with updated gas price projections during the course of this proceeding because the factors that affect natural gas prices are constantly changing, forward market prices quickly become “stale,” and their predictive power with respect to actual future prices decreases with time. Establishing rate year gas prices based on the average of the forward prices for the rate year for a three-month period of time closer to the beginning of the rate year will provide a more current projection of rate year gas prices. Therefore, PSE will adjust its requested power costs with updated forward market data prior to rates becoming effective. This would also include an update to the short-term fixed-price power contracts that are an AURORA input and the other fixed-price gas for power and index-based power and gas for power contracts that are in the "Costs Not in AURORA". In addition, some "Costs Not in AURORA" are dependent on AURORA output and will be updated when a new AURORA model run is completed.

Q. Is PSE's proposal to update its projected rate year power costs during this proceeding consistent with Commission precedent?

A. Yes. PSE's proposal to update its projected rate year power costs during this proceeding is consistent with Commission precedent. In Order 06 in Dockets UG-040640, *et al*.,[11] the Commission expressly recognized an agreement among the parties to the proceeding "that more recent data predicts the near and perhaps even intermediate term better than older data."[12] Additionally, the Commission expressly recognized in Order 08 in Dockets UE-111048 & UG-111049[13] that power costs should be determined based on costs that are reasonably expected to

[11] *WUTC v. Puget Sound Energy*, Dockets UG-040640, *et al*., Order 06 (Feb. 18, 2005).

[12] *Id.* at ¶ 116.

[13] *WUTC v. Puget Sound Energy*, Dockets UE-111048 & UG-111049, Order 08 (May 7, 2012).

be actually incurred during short and intermediate periods following the conclusion of such proceedings:

> We resolve the philosophical question raised by ICNU in favor of the practical conclusion that power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings.[14]

Consistent with the language in this Commission order, PSE's proposal to update its projected rate year power costs during this proceeding will result in power costs that are set more closely to power costs that are reasonably expected to be actually incurred during the rate year.

Q. How do more recent forecast rate year natural gas prices compare to the three-month average at January 31, 2019?

A. As of April 24, 2019, the three-month average rate year Sumas natural gas price was $2.25 per MMBtu, an increase of $0.19 per MMBtu from the $2.06 per MMBtu used to determine the prefiled rate year power costs in this proceeding.

[14] *Id.* at n.303.

5. Upstream Gas Transportation Availability

Q. Does PSE assume that its upstream pipeline capacity is 100 percent available?

A. In proposed power costs, PSE adjusted the availability of its capacity on the Westcoast Energy pipeline. The adjustment is made monthly based on actual 2017 data provided by the pipeline. In 2017, pipeline availability ranged from [redacted] percent in September to [redacted] percent in December through March. This adjustment is reasonable given the fact that the pipeline capacity is not fully available at all times due to planned and unplanned maintenance. Please see the Nineteenth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-20C, for a presentation of the 2017 availability data and the adjusted capacity used to calculate the cost of Westcoast Energy capacity.

Q. Does the adjustment reflect the impacts of the October 2018 rupture on Westcoast Energy pipeline?

A. No. Data are available for 2018, however, due to the October 2018 rupture on the Westcoast Energy pipeline, calendar year 2018 was not a normal year, therefore, PSE did not base the adjustment on that year. Calendar year 2017 was a reasonably normal year on which to base an adjustment.

Q. Did PSE make similar adjustments to other upstream pipelines?

A. No. It would be reasonable to adjust the availability of Nova, Foothills, and GTN pipelines, but data is not available to provide a reasonable estimate of availability.

6. Wind Generation

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

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

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

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 GRC, 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 rates approved in the 2011 GRC, the 2013 PCORC, Docket UE-141141 (the "2014 PCORC"), Docket UE-161135 (the "2016 Power Costs Update"), and Docket UE-170033 (the "2017 GRC"). PSE used the 2016 Vaisala forecasts in its initial filing in the 2017 GRC, but in the interest of settling that case, PSE agreed to revert to the 2010 DNV forecasts.

Q. Why did PSE update its wind forecasts in 2016 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 the Klondike III Wind Power Project. 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 the Klondike III Wind Power Project 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 for all resources. Table 13 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 8.2 percent.

Table 13. Forecasted and Actual Annual Wind Generation (MWh)

Resource	Prior Forecast*	Historical Average	Variance	Percent Variance
Hopkins Ridge	[redacted]	[redacted]	[redacted]	-9.9%
Wild Horse	[redacted]	[redacted]	[redacted]	-4.3%
Wild Horse Expansion	[redacted]	[redacted]	[redacted]	-5.4%
Lower Snake River	[redacted]	[redacted]	[redacted]	-8.4%
Klondike III	[redacted]	[redacted]	[redacted]	-19.3%
Total	[redacted]	[redacted]	[redacted]	-8.2%

* 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 Twentieth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-21C, presents comparisons of actual wind generation with the preconstruction, 2010 DNV, and 2016 wind forecasts for each wind facility, 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. Historical monthly data for all of the resources is also included in this exhibit.

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

A. Table 14 presents capacity factors[15] for each resource in the forecasts used in the 2017 GRC, the 2016 wind forecasts and historical actuals. For all resources, actual capacity factors have been below forecasts, and the capacity factors from

[15] 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.

the 2016 forecasts are lower than those of the prior forecasts but slightly above historical averages. The most extreme example is the Klondike III Wind Power Project. Because PSE has a power purchase agreement at a fixed price for output from the Klondike III Wind Power Project, updating to the more recent forecast reduces PSE's rate year power costs.

Table 14. Forecasted and Actual Annual Wind Capacity Factors

Resource	Prior Forecast*	Historical Average	2016 Forecast
Hopkins Ridge	[redacted]	[redacted]	[redacted]
Wild Horse	[redacted]	[redacted]	[redacted]
Wild Horse Expansion	[redacted]	[redacted]	[redacted]
Lower Snake River	[redacted]	[redacted]	[redacted]
Klondike III	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

* 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.

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

A. The 2016 Vaisala long term forecast provides the expected long-term mean potential net annual energy production value, i.e. the P50, from each resource.

Q. How did PSE shape the wind generation for calculating rate year power costs?

A. The 2016 monthly wind forecasts are shaped based on default hourly shapes provided by the AURORA model. The total energy ties to the third party forecast. In prior proceedings PSE used average hourly wind volumes that were provided with forecasts, which do not reflect the variability of wind generation ranging from zero to full output.

<u>7. Load Forecast</u>

Q. What load forecast did PSE use in running its AURORA hourly dispatch model for the rate year?

A. PSE used the most current electric load forecast—the F2018 load forecast—as the rate year demand input to the AURORA model. The electric load forecast, net of demand-side resources (conservation), for the rate year is 23,152,655 MWh, or 2,643 aMW. This is a decrease of 119,892 MWh, or 0.5 percent from the 2017 GRC load forecast of 23,272,547 MWhs, or 2,657 aMW. The 2017 GRC power cost forecast used the then-current load forecast, the F2016 load forecast, for the 2017 GRC rate year January through December 2018.

<u>8. Operating Reserves</u>

Q. What operating reserves are included in rate year power costs?

A. Rate year power costs include estimated (i) costs of contingency reserves, (ii) costs related to balancing load with wind and other resources every hour, and (iii) day ahead wind integration costs. These costs were also included in power costs in the 2017 GRC Settlement.

Q. What are contingency reserves and how are they calculated?

A. As a Balancing Authority, PSE is required by North American Electric Reliability Corporation ("NERC") and Western Electric Coordinating Council ("WECC") standards to fulfill a Contingency Reserve Obligation. Contingency reserves are capacity reserves that Balancing Authority operators are required to maintain to help preserve the stability of the bulk power system during system disturbance events such as a generating unit tripping offline or an unexpected transmission line outage. They are incremental reserves, which means the Balancing Authority operator must have the ability to increase generation in the event of a disturbance to maintain its area balance. In the WECC, contingency reserves are defined as three percent of the load in the Balancing Authority plus three percent of online generation located within or dynamically tied to the Balancing Authority. Fifty percent of the Contingency Reserve Obligation must be maintained by generating units that are online (spinning), and up to 50 percent can be provided by units that are offline but can be brought online within 10 minutes (non-spinning).

Q. Has PSE's Contingency Reserve Obligation changed since rates were established in the 2017 GRC Settlement?

A. Yes. WECC is currently in a trial period that allows a Balancing Authority to meet its entire Contingency Reserve Obligation with resources that are not spinning. This is a trial period. WECC is expected to make a decision about whether to make this change permanent. Since that decision has not yet been made and the permanent legal requirement is still to have 50 percent of

Contingency Reserve Obligation provided by resources that are spinning, PSE has modeled Contingency Reserve Obligation with 50 percent spinning and 50 percent non-spinning resources for projecting power costs in this proceeding.

Q. What are costs related to balancing load with wind and other resources every hour?

A. PSE must enter each hour with sufficient reserves available to continuously balance its load with resources. These costs represent the cost of reserving that capacity each hour.

Q. What has changed regarding costs related to balancing load with wind and other resources every hour since the 2017 GRC?

A. As indicated earlier in this testimony, in this proceeding PSE included these costs in AURORA, whereas in prior proceedings they were calculated in a separate model, the Hour-Ahead Balancing Model, downstream of AURORA using AURORA output. Conceptually, the reserves costs now calculated in AURORA are the same as those previously calculated in the Hour-Ahead Balancing Model. There is an update to the amount of hour ahead reserves required.

Q. What level of hour ahead reserves was assumed in the 2017 GRC?

A. In the 2017 GRC and prior proceedings, PSE assumed an hour-ahead reserve requirement of 106 MW. This level was based on analysis conducted when PSE developed OATT rates for Schedule 13, Regulation and Frequency Response.

Q. What level of capacity does PSE reserve on an hour-ahead basis operationally?

A. Operationally, the amount of reserves varies from hour to hour. It also varies depending on whether reserves are incremental, meaning reserved capacity provides the ability to increase production, or decremental, meaning resources provide the ability to reduce generation. PSE must go into each hour with a balanced base schedule in order to participate in the EIM, and CAISO has requirements for incremental and decremental flexible ramping reserves.

Generally, those reserves are 106 MW of incremental reserves and 145 MW of decremental reserves. In addition to these flexible ramping reserves PSE holds 35 MW of reserves for regulation in both directions. In total, this adds up to 141 MW of incremental reserves and 180 MW of decremental reserves. These are the amounts used in AURORA to model the cost of hour ahead reserves needed to balance load with wind and other resources each hour. They are higher than the 106 MW PSE has used historically to estimate hour-ahead reserve costs.

Q. Are the costs of hour-ahead reserves for the Skookumchuck and Lund Hill PPAs included in rate year power costs?

A. Hour-ahead reserves costs for the Skookumchuck PPA are included in rate year power costs, but hour-ahead reserves costs for the Lund Hill PPA are not. The Lund Hill PPA requires the resource owner to be responsible for the cost of deviations from its hour ahead forecast, whereas the Skookumchuck PPA does not.

PSE calculated rate year costs for Skookumchuck PPA hour-ahead costs based on the rates that PSE charges third parties for the same service, as published in Schedule 13 of its OATT. Please see the Twenty-First Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-22C, for the development of Skookumchuck PPA hour-ahead costs.

Q. What are day-ahead wind integration costs?

A. Day-ahead wind integration costs have been included in PSE's rate year power costs since the 2013 PCORC. They are the costs and benefits that occur between the day-ahead and real-time markets due to the uncertainty of wind power generation. PSE sets up its position in the day-ahead market based on the day-ahead wind forecast. When the portfolio position is updated on an hour-ahead basis with an updated wind forecast, there are costs and benefits associated with movements in the wind forecast and market prices between the day-ahead and hour-ahead positions.

Since the 2013 PCORC, PSE has calculated these costs and benefits based on historical hourly generation and price data and included the net cost in rate year power costs, adding recent data as time has passed. In this proceeding, PSE used costs through December 2018 to calculate day-ahead costs by resource.

Q. Has PSE changed its calculation of these costs since the 2017 GRC Settlement?

A. PSE made a minor modification to its approach to day-ahead costs in this proceeding. Because there is a new wind resource (i.e., the Skookumchuck PPA) scheduled to come online prior to the rate year, data for estimating day ahead wind integration costs were needed. PSE used the historical data from all of the other wind resources to calculate a weighted average rate to apply to the Skookumchuck PPA. In the process, PSE decided to use weighted-average costs based on historical data for existing resources as well.

In prior proceedings, PSE calculated an actual day-ahead cost for each resource for each historical year of operation based on hourly movements in wind forecasts and market prices. For each resource, PSE assumed the simple average of those annual costs as the rate year cost. Those costs are still calculated based on hourly movements in wind forecasts and market prices. The difference is that rather than averaging annual historical costs and assuming those values for the rate year, PSE calculated a weighted-average rate per MWh for each resource from that historical data and applied it to rate year wind production to yield a rate year cost. For existing resources, the rates were based on historical resource specific data. For the Skookumchuck PPA, the melded average rate for all other resources was used. Please see the Twenty-Second Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-23C, for the calculation of rate year day-ahead costs.

<u>9. BPA Transmission Rates</u>

Q. Are BPA transmission rates expected to change before or during the rate year?

A. Yes. BPA is in the process of a combined power and transmission rate proceeding to set new rates for BPA's fiscal years 2020-2021 (October 1, 2019, through September 30, 2021) (the "BPA 2020 Rate Case").

Q. Is PSE participating in the BPA 2020 Rate Case?

A. Yes. PSE is an intervener in the BPA 2020 Rate Case to advocate for PSE customers' interests to ensure any rate changes are supported by the facts presented. Consistent with past practice, PSE has worked with other parties to recommend ways to reduce the rate increases, which would be effective October 1, 2019, through September 30, 2021. PSE has joined in a partial rates settlement with other BPA transmission customers, and these rates will likely be adopted by the BPA Administrator in a Record of Decision (ROD).

Q. How does PSE propose to include BPA's planned transmission rate changes in rate year power costs?

A. PSE has included projected BPA transmission rates from its proposed settlement in the BPA 2020 Rate Case in the pro forma transmission costs included in rate year power costs. These rates are proposed to be effective October 1, 2019. BPA may update its projected rate changes in the 2020 BPA Rate Case during the course of this proceeding, and PSE will update rate year power costs to reflect any such changes.

<u>10. Exhibits Presenting Specific Input Data and Calculations for Proposed Rate Year Power Costs</u>

Q. Has PSE provided other exhibits to support proposed rate year power costs in this proceeding?

A. Yes. The following exhibits present specific input data and calculations for proposed rate year power costs:

(i) The Twenty-Third Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-24C, presents Colstrip fixed fuel costs.

(ii) The Twenty-Fourth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-25C, presents contract costs of Mid-C hydro resources.

(iii) The Twenty-Fifth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW26C, presents BPA transmission costs.

(iv) The Twenty-Sixth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-27C, presents the gas mark-to-model and open transport value.

(v) The Twenty-Seventh Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-28C, presents fixed gas-for-power transportation costs.

(vi) The Twenty-Eighth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-29C, presents distillate fuel incremental costs.

(vii) The Twenty-Ninth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-30C, presents an adjustment to remove non-fuel costs that are included in

AURORA's peaker start costs. These are not power costs, but because they are bundled startup fuel costs in AURORA output, they need to be removed.

(viii) The Thirtieth Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-31C, presents estimated costs of incremental transmission necessary to meet peak loads.

(ix) The Thirty-First Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-32, presents Other Power Costs chargeable to FERC account 557. These are actual costs from the test year ended December 31, 2018.

E. Comparison with Power Costs in Current Rates

Q. How do the power cost projections in this proceeding compare with the power cost projections approved in the 2017 GRC Settlement?

A. Proposed power costs of $743.5 million are 4.5 percent higher than the $711.5 million approved in the 2017 GRC Settlement.

Q. What are the causes of the change in projected power costs relative to the 2017 GRC Settlement?

A. The following items caused the majority of the change to projected rate year power costs from the 2017 GRC Settlement:

(i) The addition of the Skookumchuck and Lund Hill PPAs to serve Green Direct customers;

(ii) A scheduled increase in the rate charged by Transalta Centralia Generation for Coal Transition Power;

(iii) Increased gas transportation costs driven by scheduled rate increases on Northwest Pipeline effective in October 2018 and tariff increases on Westcoast Energy pipeline effective in January 2019;

(iv) Increased costs related to BPA transmission contracts; and

(v) Increases to other power supply expenses.

Q. What does PSE request from the Commission regarding rate year power costs?

A. PSE respectfully requests that the Commission approve PSE's proposed rate year power costs of $743.5 million.

VIII. COMMISSION APPROVED POWER COSTS METHODOLOGY

Q. What does Commission Approved refer to?

A. WAC 480-07-510(3)(c)(iii) states:

> If a party proposes to calculate an adjustment in a manner different than the method the commission most recently accepted or authorized for the company, the party must also include in testimony and exhibits the rationale for, and documents that demonstrate, how that adjustment would be calculated under the methodology previously accepted by the commission and must explain the reason for the proposed change. Commission approval of a settlement does not constitute commission acceptance of any underlying methodology unless the commission so states in the order approving the settlement.

PSE proposes to make methodological changes to its estimate of rate year power costs. To be consistent with the requirement, PSE has provided an estimate of power costs based on its prior methodology.

Q. In what proceeding did the Commission last accept or authorize a methodology for estimating power costs?

A. The Commission last authorized power costs in a litigated proceeding in the 2011 GRC. In all proceedings since then, PSE's power costs have been determined by settlements approved by the Commission.

Q. Was the methodology used to estimate power costs in the 2011 GRC used as the Commission Approved methodology in this proceeding?

A. Yes, with some minor adjustments. What PSE has labeled Commission Approved is consistent with the 2017 GRC Settlement; however, the differences between the 2017 GRC Settlement and the 2011 GRC are minor enough that the 2017 GRC Settlement is a reasonable proxy for the 2011 Commission Approved methods. The 2017 GRC Settlement is also consistent with proceedings that took place subsequent to the 2011 GRC, specifically the 2013 PCORC, the 2014 PCORC and the 2016 Power Cost Update.

Q. How was the power cost methodology used in the 2017 GRC Settlement different from that used in the 2011 GRC?

A. There are four differences, some of which are changes to inputs rather than changes to methodology. In the interest of transparency, they are all presented here.

(i) Transmission reassignment revenue. In the 2017 GRC Settlement, test year actual amounts were assumed for the rate year. In the 2011 GRC, the

2013 PCORC, the 2014 PCORC, and the 2016 Power Cost Update, actuals from a recent 12-month period were assumed.

(ii) Day-ahead wind integration costs. In the 2017 GRC Settlement, the 2013 PCORC, the 2014 PCORC, and the 2016 Power Cost Update, actual day-ahead and real-time prices were used. In the 2011 GRC, a ratio of day ahead to real time prices was applied to AURORA-generated prices.

(iii) Wild Horse Wind Facility within-hour wind integration costs. Wind integration costs of the Wild Horse Wind Facility were included in the 2017 GRC Settlement, the 2011 GRC, the 2013 PCORC, the 2014 PCORC, and the 2016 Power Cost Update. In the 2011 GRC, only Wild Horse Wind Facility costs were calculated. In the 2013 PCORC, the 2014 PCORC, the 2016 Power Cost Update, and the 2017 GRC, more complete reserve costs were calculated and allocated between Wild Horse Wind Facility, third-party generation, and load, but only Wild HorseWind Facility costs were included as wind integration costs in rate year power costs. So, the same costs were included in the 2017 GRC Settlement as in the 2011 GRC, but the approach used to develop them was slightly different.

(iv) Balancing and contingency reserves. These costs were included in rate year power costs in the 2017 GRC Settlement, and no party took issue with them in that proceeding. They had not been included in prior proceedings.

Because these differences between the 2011 GRC and the 2017 GRC Settlement are relatively minor, PSE uses the 2017 GRC Settlement methodology as a proxy for the Commission Approved for comparison purposes in this proceeding.

Q. What are the methodology differences between the proxy Commission Approved approach and PSE's proposed approach in this proceeding?

A. As discussed earlier in this testimony, PSE adopted a two-zone model in AURORA to allow for the calculation of reserves costs in AURORA rather than using a separate spreadsheet model.

PSE changed its interpretation of 80-year hydro to taking the average hydro generation based on 80 years of streamflow data as an input to a single AURORA run instead of performing a separate AURORA run for each of the 80 years of streamflow data and taking the average of the output.

In its proposed power costs, PSE updated the wind forecast from 2010 DNV forecasts and preconstruction forecasts to long term forecasts developed in 2016 by Vaisala (Avangrid Renewables, LLC for the Klondike III Wind Power Project), which incorporate actual historical data from the plants. In the Commission Approved version, 12-months-by-24-hour matrices of average output were used to provide wind shapes, which meant wind output was always average and contained no extremes such as full capacity or zero capacity generation. In the proposed approach, AURORA default wind shapes were used and calibrated to forecasted production for each resource, so generation more realistically displays extremes in some hours rather than average output in all hours.

Q. How do PSE's proposed power costs compare to the Commission Approved power costs?

A. Rate year power costs using the Commission Approved approach are $741.1 million, $2.4 million less than the $743.5 million of proposed rate year power costs, as presented in Table 15.

Table 15. Rate Year Power Costs – Proposed and Commission Approved Methodologies ($ in millions)

	Proposed	Commission Approved
AURORA	$487.3	$476.1
Costs Not in AURORA	$256.2	$265.0
Projected Rate Year Power Costs	$743.5	$741.1

Please see the Thirty-Second Exhibit to the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-33C, for a comparison of Commission Approved power costs with proposed power costs in this proceeding.

IX. CONCLUSION

Q. Does this conclude your prefiled direct testimony?

A. Yes, it does.