EXH. PKW-1CT
DOCKET UE-20____
2019 PCA PERIOD COMPLIANCE FILING
WITNESS: PAUL K. WETHERBEE

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of PUGET SOUND ENERGY For Approval of its 2020 Power Cost Adjustment Mechanism Report	DOCKET UE-20____

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF

PAUL K. WETHERBEE

ON BEHALF OF PUGET SOUND ENERGY

REDACTED VERSION

APRIL 30, 2020

PUGET SOUND ENERGY

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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 2380 116th Ave 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. It is Exhibit PKW-2.

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

A. I am responsible for oversight of all Front Office activities including power and gas trading, the hedging program, and the dispatch of PSE's generating assets and related transmission.

Q. Please summarize the contents of your testimony.

A. First, I provide background information regarding the Power Cost Adjustment ("PCA") mechanism. I then describe PSE's management of power costs during the period that began on January 1, 2019 and ended on December 31, 2019. Finally, I compare PSE's actual allowable power costs for the 2019 PCA Period to the baseline variable power costs included in rates during the 2019 PCA Period. The baseline power cost rate approved in PSE’s 2017 general rate case, Docket UE-170033 (“2017 GRC”) went into effect December 19, 2017 and remained the effective rate through April 30, 2019. The contingent calculation of the baseline power cost rate to account for the transition of Microsoft to retail wheeling service, also approved in PSE’s 2017 general rate case, went into effect May 1, 2019 and remained the effective rate for the remainder of the 2019 PCA Period. The Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, contains further information regarding the baseline rate for the 2019 PCA Period.

II. BACKGROUND REGARDING THE PCA MECHANISM

Q. Why does PSE have a PCA mechanism?

A. Volatility in wholesale energy markets coupled with variations in power supply and load volumes can lead to significant differences between the actual cost of PSE’s power supply portfolio and the costs currently included in customer rates. The PCA mechanism seeks to balance the risk of such power cost differences between customers and PSE by providing a method to share costs and benefits if power costs deviate significantly from those embedded in rates.

The PCA mechanism originally took effect on July 1, 2002 following a settlement agreement that originated in PSE’s 2001 general rate case. As part of PSE’s 2013 power cost only rate case, Docket UE-130617, PSE and parties to that proceeding initiated a collaborative process to address issues relevant to the PCA mechanism.

That process resulted in a multiparty settlement that changed certain elements of the PCA.

The multiparty settlement was approved by the Commission and the changes became effective on January 1, 2017.

Q. How does the PCA mechanism work?

A. The PCA mechanism accounts for differences in PSE's actual power costs relative to the power cost baseline included in rates. The costs or benefits of such power cost variances are shared between PSE and customers according to three graduated levels of power cost variance or sharing bands. The dead band includes the first $17 million of power cost variance (positive or negative). Within the dead band, 100 percent of costs or benefits are retained by PSE. The first sharing band includes power cost variances between $17 and $40 million (positive or negative). Within this band, costs (under-recovered) are shared 50 percent to PSE and 50 percent to customers while benefits (over-recovered) are shared 35 percent to PSE and 65 percent to customers. The second sharing band includes power cost variances over $40 million (positive or negative). All variances in this band are shared 10 percent to PSE and 90 percent to customers, regardless of whether they are costs or benefits.

The customers' share of power cost variances is accounted for each year and deferred until the cumulative balance in the deferral account triggers a surcharge or refund. The Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, contains further information regarding the accounting for the cumulative balance.

III. 2019 PCA PERIOD POWER COSTS

A. <u>PSE's Management of its Power Portfolio and Fuel Supply for the 2019 PCA Period</u>

Q. What governance does PSE have over its power cost transactions?

A. PSE's Energy Supply Merchant ("ESM") department is composed of energy market analysts, energy traders, and other professionals. The ESM department develops and implements portfolio management strategies and transacts in the markets for power and gas. The ESM department was under my direction for all of the 2019 PCA Period.

PSE's Energy Risk Control ("ERC") department is responsible for independently monitoring, measuring, quantifying, and reporting official risk positions and performing credit analysis. The ERC department is led by the Corporate Treasurer. PSE's Energy Management Committee ("EMC"), composed of five PSE officers, oversees the activities performed by both the ESM and ERC departments. The EMC is responsible for providing oversight and direction on all portfolio risk issues in addition to approving long-term resource contracts and acquisitions. The EMC provides policy-level and strategic direction on a regular basis, reviews position reports, sets risk exposure limits, reviews proposed risk management strategies, and approves policy, procedures, and strategies for implementation by PSE staff. PSE's Procedures Manual and Energy Risk Policy lay out the policies that govern energy portfolio management activities and define roles and responsibilities of various departments. In addition, PSE's Board of

Directors provides executive oversight of these areas through the Audit Committee.

Q. Did PSE acquire any new resources during the 2019 PCA Period?

A. Yes. PSE acquired new resources in the form of off-system physical or financial purchases and sales of power and fuel to generate power. The majority of these transactions were short-term purchases or sales of power and natural gas. Such transactions are made in response to changes in load or resource availability as well as changes in market heat rates, which guide PSE's decisions of whether to dispatch gas-fired generation or to buy power in the market.

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

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

Q. Please explain least cost dispatch.

A. The ESM 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 loads, there is often excess capacity. To optimize the portfolio, ESM staff maximizes asset value by selling excess 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 Procedures Manual.

Q. What are the current hedging strategies approved by the EMC?

A. The purpose of hedging is to reduce the effects of price volatility in power costs prior to delivery. PSE's hedging program is managed in accordance with the EMC-approved Procedures Manual. The Procedures Manual provides guidance and risk management strategies for hedging exposure in two different time periods, 1) the Programmatically Managed Hedge period and 2) the Actively Managed Hedge period. The Programmatically Managed Hedge period begins [redacted] in advance of delivery. The ESM department uses the Programmatically Managed Hedge program to systematically reduce PSE's net power portfolio exposure (including to natural gas for power generation) so that, as a month rolls into the Actively Managed Hedge period, the exposure for that month will be within the monthly EMC-approved exposure limit.

The Actively-Managed Hedge program begins [redacted] in advance of delivery. During this period, ESM staff monitors positions on a daily basis, and authorized traders execute transactions to manage exposure within monthly and [redacted] authority limits established by the EMC.

REDACTED

Q. How is electric portfolio exposure measured?

A. Exposure is calculated individually for on-peak, off-peak, and gas for power positions. EMC-approved exposure limits apply to the net spot exposure of all three positions. Spot market exposure is measured by multiplying the net open position, in megawatt hours or million British Thermal Units ("MMBtu"), by the power or gas market price, respectively. It represents the net dollar amount that PSE has not hedged during a specific period, given forecasted load and generation volumes, hedged volumes, and simulated market prices. PSE performs this calculation using 250 simulations of forward power and gas prices to generate a probabilistic measurement of portfolio exposure.

Q. How does PSE use the electric portfolio exposure limits to help make hedging decisions?

A. Once PSE's aggregated energy position and net exposure are defined for a particular period, the ESM department executes transactions for the purchase or sale of gas or power to stay within EMC-determined exposure limits. Execution entails entering into specific transactions with approved counterparties under approved master agreements subject to credit limits.

Q. Does the ESM department rely only on net exposure to implement the hedge programs?

A. No. The ESM department also analyzes market prices and fundamentals that impact the wholesale electric and gas markets. The ESM department also determines when and with whom to execute transactions to manage net exposure.

Q. What information does the ESM department rely on to inform portfolio management decisions?

A. In addition to the net energy position and power portfolio exposure, the ESM department utilizes a wide set of tools and sources of information to make informed decisions about dispatching plants, purchasing fuel, and executing hedges within EMC-approved limits. The ESM department collects and analyzes regional supply and demand data such as weather trends and hydro generation conditions. Additionally, ESM reviews forecasted wholesale market prices and industry publications. ESM receives real-time information from sources including Intercontinental Exchange (“ICE”) Data and Analytics, live ICE price data, and brokers.

The ESM department reviews operational events, discusses market trends, and reviews supply and demand information. The team works together to understand exposures in the portfolio and determine hedging priorities.

The ESM department may also use such information to develop recommendations to the EMC regarding potential changes to PSE’s overarching hedging strategies or to recommend transactions that do not fall within current strategies.

Q. Does PSE use any other information to manage its energy portfolio?

A. Yes. The ERC department is responsible for establishing and monitoring counterparty credit limits in accordance with the EMC-approved Credit Risk Management Policy. Counterparty-specific exposure is calculated and monitored frequently, and ESM staff is permitted to transact only within established credit limits.

B. <u>PSE’s 2019 PCA Period Actual Power Costs</u>

Q. How did PSE’s actual power costs for the 2019 PCA Period compare to power costs recovered through rates?

A. During the 2019 PCA Period, PSE recovered $689.0 million of power costs through the variable baseline rate and incurred actual allowable power costs of $756.3 million. This $67.2 million under-recovery is outside of the $17 million dead band, so PSE will share a portion of these costs with customers according to the PCA sharing bands. Exhibit PKW-3 includes power cost under- and over-recoveries by month during 2019.

Q. Why did actual power costs differ from those set in rates?

A. The actual costs of power delivered to PSE’s system always differ from those established in rates because actual power costs reflect the actual resources available to PSE and the realized outcome of multiple power cost variables. These variables include:

(i) weather and power usage which affects demand (load),

(ii) streamflows, which affect the supply of hydroelectric energy,

(iii) unplanned generation outages and the timing of planned outages,

(iv) contract rates,

(v) output from variable energy resources,

(vi) transmission and transportation constraints, and

(vii) market energy prices.

Further, while power costs included in rates are estimated "as closely as possible to costs that are reasonably expected to be actually incurred,"[1] estimates are limited by regulatory normalizing assumptions. Specifically, rates established in PSE's 2017 GRC normalized power cost variables by utilizing:

(i) a weather normalized load forecast,

(ii) hydro generation from 80 years of streamflow data,

(iii) forecasts of long-term average wind generation,

(iv) gas prices equal to a three-month average of forward market prices,

(v) model-generated market power prices, and

(vi) historical average forced outage rates.

[1] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-040640, *et al.*, Order 06 at ¶ 108 (Feb. 18, 2005).

Q. What were the primary causes of differences between PSE's actual power costs and power costs recovered in rates during the 2019 PCA Period?

A. During the 2019 PCA Period, PSE's total actual allowable power costs were $67.2 million higher than power costs recovered in rates. This under-recovery is primarily the result of:

(i) a high-price market event that was the culmination of a number of separate market constraining events and affected the entire Pacific Northwest region in February and March,

(ii) lower generation from PSE's hydro and wind facilities,

(iii) rate increases for long-term power and transmission contracts, and

(iv) lower load across most of the year.

Q. Was there an independent review of the February and March event?

A. Yes. Western Electricity Coordinating Council ("WECC") assessed the event to determine the implications to system reliability and provided a comprehensive report, which is provided here as Exhibit PKW-4.

Q. What events contributed to the high natural gas and electric power prices that occurred in February and March?

A. The Pacific Northwest and western Canada experienced high prices for natural gas and electric power throughout most of February and March 2019, with prices spiking from March 1 to 4, 2019.[2] The high prices were brought on by a combination of:

(i) cold weather,

(ii) reduced availability of the Westcoast Pipeline,

(iii) low inventory at the Jackson Prairie gas storage facility,

(iv) a derate on a transmission line from California, and

(v) low regional hydro and wind generation.

Q. How did actual market prices differ from those in rates throughout the market event?

A. For February and March 2019, Sumas gas prices averaged $19.38/MMBtu, compared to $3.10/MMBtu assumed in rates. Mid-C flat power prices averaged $53.70/MWh, compared to $26.91/MWh in rates. See Exhibit PKW-5C for average daily Sumas gas and Mid-C flat power prices for November 2018 through March 2019.[3] On Friday, March 1, due to restricted supply conditions and elevated demand caused by low temperatures, Mid-C power prices rose to the Federal Energy Regulatory Commission ("FERC") maximum cap of $1,000/MWh. Daily average gas prices rose to $160/MMBtu.

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[2] *See* Exh. PKW-4 at 2.

[3] November and December 2018 prices are included to provide context for reviewing the February and March prices.

Q. How did cold weather contribute to the high-price market event?

A. Extended below-average temperatures in western Canada and areas of the Pacific Northwest created prolonged high heating demand on both the gas and power systems.[4] Between February 1 and March 14, average daily temperatures were six degrees below normal at SeaTac International Airport. During this period, PSE's average daily loads were 19 percent above the forecast used in rates. See Exhibit PKW-6C for daily load variance from rates and temperature variance from normal for February and March. The constant low temperatures stressed natural gas supply, which was already constrained after the rupture of the Westcoast Pipeline near Prince George, British Columbia ("BC"), in October 2018.[5]

Q. How did reduced availability of the Westcoast Pipeline contribute to the market event?

A. The Northwest market relies on the Westcoast Pipeline to ship gas from northern BC to the US border at Sumas. The rupture on the Westcoast pipeline reduced the capacity on the system by approximately 18 percent on average in the first quarter of the 2019 PCA Period, often more during maintenance work. Exhibit PKW-7C presents the availability of the Westcoast Pipeline for January 2018 through July 2019. These capacity restrictions not only limited the amount of gas that PSE was able to source from northern BC, they also limited the supply available to the Sumas market.

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[4] *See* Exh. PKW-4 at 5.
[5] *See* Exh. PKW-4 at 6.

Q. How did low inventory at Jackson Prairie contribute to the market event?

A. Extensive withdrawals earlier in the winter meant that Jackson Prairie was operating at low pressures leading into March.[6] The amount of supply from storage available to PSE and other shippers was limited, increasing the reliance on the Sumas market to meet demand.

Q. How did a derate on a transmission line from California contribute to the market event?

A. The Pacific Intertie is a direct current ("DC") transmission line that connects the Pacific Northwest to California. While the Pacific Northwest generally exports power to California, it relies on imported power from California for additional supply during winter peak events.[7] Beginning on February 23, the Pacific DC Intertie was derated from 975 MW to 0 MW south to north for previously scheduled and approved transformer maintenance.[8] This derate restricted the Pacific Northwest market's ability to import power from California, further tightening supply at the Mid-C market hub.

Q. How did low regional hydro and wind supply contribute to the market event?

A. Bonneville Power Administration ("BPA") reported that dry conditions across the Columbia River Basin forced Grand Coulee Dam to operate at minimum

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[6] *See* Exh. PKW-4 at 7.
[7] *See* Exh. PKW-4 at 10.
[8] *See* Exh. PKW-4 at 10.

discharge rates through February and March to support the fish operations below Bonneville Dam. Hydro supply in BC was also reduced to record seasonal low levels. As supply conditions became tighter, BC Hydro responded to BPA's request to release more water and increase downstream generation, despite the fact that it was experiencing extremely low hydro conditions.[9] Meanwhile, power from wind generation was also very low, with an average capacity factor of 11 percent for all wind resources in the Northwest Power Pool, compared to 25 percent and 41 percent for the same period in 2018 and 2017, respectively.[10]

Q. How did PSE's ESM department manage power costs leading up to the February and March high-price conditions?

A. Consistent with its Programmatically Managed Hedge program, PSE executed transactions to gradually reduce portfolio exposure to within program limits by the time each month rolled into the Actively Managed Hedge period. Exhibit PKW-8C shows PSE's portfolio exposure for the month of February 2019, and Exhibit PKW-9C shows the same for March 2019. PSE purchased additional power and gas following the Westcoast Pipeline rupture and continued to monitor exposure throughout the Actively Managed Hedge period for each month.

[9] *See* Exh. PKW-4 at 8.
[10] *See* Exh. PKW-4 at 8.

C. <u>PSE's 2019 PCA Period Power Costs Variance to 2017 GRC</u>

Q. Please summarize PSE's costs and baseline rate revenue during the 2019 PCA Period compared to the 2017 GRC.

A. Power costs were $55.6 million above the level included in the 2017 GRC. Delivered load was 351,702 MWh below the level assumed when the baseline rate was established, and this lower load contributed $11.6 million to the under-recovery. Delivered load was below the amount included in rates in eight out of twelve months in 2019. Delivered load in February was 242,906 MWh above the amount included in rates, partially offsetting the lower loads throughout the remainder of the year. Exhibit PKW-10C presents 2019 PCA Period delivered load by month.

Table 1 below provides a comparison of 2019 power costs relative to those included in rates by resource type, and the impact of load variance on baseline rate revenue. These variances sum to the $67.2 million of under-recovered costs. The 2017 GRC amounts used to calculate these variances include four months of costs and load prior to the Microsoft transition and eight months after the transition.

Table 1: 2019 PCA Period Cost Recovery Summary	
Cost above / (below) 2017 GRC	**$M**
Coal	22.2
Natural Gas Fuel and Transportation	(77.4)
Long Term Contracts	(1.6)
Market Purchases and Sales	95.0
Transmission	9.0
Other	8.5
Total Costs	**55.6**
Revenue (above) / below 2017 GRC	
Load	11.6
Total Revenue	**11.6**
Total under / (over) - recovery	**67.2**

Q. Please summarize PSE's generation during the 2019 PCA Period compared to the 2017 GRC.

A. Table 2 below provides a comparison of the resources used to serve load relative to the resources included in rates.

Table 2: 2019 PCA Period Generation and Load Relative to Rates		
Generation above / (below) rates	**MWh**	**%**
Hydro	(1,006,597)	-23.1%
Wind	(369,080)	-18.1%
Colstrip	513,836	13.4%
Gas-fired	530,902	8.6%
Contracts	(97,597)	-2.5%
Market Purchases and Sales	(245,055)	-9.2%
Load (generated, purchased, and interchanged)	(673,591)	-3.4%
Delivered Load	(351,702)	-1.7%

Q. How did coal fuel costs impact power costs during the 2019 PCA Period?

A. Actual coal fuel costs during the 2019 PCA Period were $22.2 million higher than the amount included in rates. These higher costs were the result of more coal-fired generation than assumed in rates. Additionally, the cost of coal per MWh during

2019 was higher than the amount included in rates due to fuel contract cost escalation. Colstrip generation for the year was 513,836 MWh above rates, due largely to higher market power prices.

Q. How did natural gas fuel and transportation impact power costs during the 2019 PCA Period?

A. Natural gas fuel and transportation costs during the 2019 PCA Period were $77.4 million lower than the amount included in rates. Actual natural gas-fired generation was 530,902 MWh higher than the amount in rates, due to higher market heat rates during June through October 2019. However, the cost of additional fuel was more than offset by higher revenue from gas sales and transport optimization. During the February and March market event, when market heat rates were low, PSE was able to sell previously purchased gas and buy power in the market. In February and March, sales of physical gas reduced costs by $81.0 million relative to the amount included in rates.

Q. How did long term contracts impact power costs during the 2019 PCA Period?

A. Long term contract costs during the 2019 PCA Period were $1.6 million lower than the amount included in rates. Actual generation from long-term contracts was 97,597 MWh below the level assumed in rates, due to lower receipts under PSE's Klondike III wind contract and, in aggregate, PSE's Schedule 91 tariff contracts. On average, long-term contract rates were $55.08/MWh in 2019, compared to

$53.17/MWh included in rates, a 3.6 percent increase due to annual escalation built into the contract rate structures. The impact of higher contract prices was more than offset by lower volumes from those contracts.

Q. How did market purchases and sales impact power costs during the 2019 PCA Period?

A. The net cost of market purchases and sales during the 2019 PCA Period was $95.0 million higher than the amount included in rates. Generation from net market purchases and sales was 245,055 MWh below the amount included in rates.

Actual generation from PSE's hydro assets was 1,006,597 MWh lower than the level in rates, while generation from PSE's wind assets was 369,080 MWh lower than the level in rates. These volumes were replaced by market purchases. See Exhibit PKW-11C for actual hydro volumes by month for 2019. See Exhibit PKW-12C for actual wind volumes by month for 2019. In total, under-generation from hydro and wind resources increased 2019 PCA Period power costs by $44.3 million relative to the amount included in rates. See Exhibit PKW-13C for an estimate of hydro and wind replacement power costs by month for the 2019 PCA Period.

Also, average market heat rates were significantly lower than assumed in rates for February through May 2019. Lower market heat rates indicate that it is cheaper to purchase power from the market than to generate from a gas-fired resource. PSE's net market purchases and sales exceeded the amount in rates by $110.8 million during February and March, when average market heat rates fell between two and four MMBtu/MWh, far below the economical operating range of PSE's gas-fired resources. Generation from market purchases and sales for this period exceeded the amount in rates by 758,376 MWh.

Additionally, average market heat rates were significantly higher than those assumed in rates for June through September and December, indicating that it was cheaper to generate power from gas-fired resources than to purchase from the market. During those months, PSE's market sales exceeded the level assumed in rates by 1,386,824 MWh. Finally, as was previously mentioned, loads were down for most of the year, so PSE was able to sell excess generation that was produced during periods with high market heat rates rather than use it to meet load.

Q. How did transmission costs impact power costs during the 2019 PCA Period?

A. During the 2019 PCA Period, the cost of third-party transmission was $4.1 million higher than the costs included in rates. These higher costs were the result of rate increases that occurred between the 2017 GRC filing and the 2019 PCA Period. Additionally, offsetting revenues from transmission reassignments[11] were $4.9 million lower than the amount assumed in rates. Overall, higher net purchased transmission costs increased 2019 PCA Period power costs by $9.0 million relative to the amount in rates.

[11] Reassignments refer to PSE's sale of uncommitted transmission capacity.

IV. CONCLUSION

Q. Were PSE's power costs during the 2019 PCA Period prudently incurred?

A. Yes, PSE's power costs for the 2019 PCA Period were prudently incurred. PSE's management of its power costs during the 2019 PCA Period was reasonable. PSE has structures and processes in place to formulate strategies for managing power costs and executed those strategies, taking into account information and variables associated with managing a complex resource portfolio within a dynamic market environment. The deferral balance set forth in PSE's 2019 PCA Period report is calculated in accordance with the amended PCA settlement and the Commission's orders in UE-011570.

Q. Does that conclude your testimony?

A. Yes, it does.