EXH. PKW-1CT
DOCKETS UE-22____
2021 PCA 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 2021 Power Cost Adjustment Mechanism Report**	**DOCKET UE-22____**

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF

PAUL K. WETHERBEE

ON BEHALF OF PUGET SOUND ENERGY

REDACTED VERSION

APRIL 29, 2022

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF 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 P.O. Box 97034, Bellevue, Washington, 98009. I am employed by Puget Sound Energy ("PSE") as Director, Energy Supply Management.

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 Management?

A. As Director, Energy Supply Management 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;

(iii) managing work groups that address resource adequacy conformance, regional market design, merchant transmission optimization, and the integration of generation assets.

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, 2021 and ended on December 31, 2021. Finally, I compare PSE's actual allowable variable power costs for the 2021 PCA Period to the baseline variable power costs included in rates during the 2021 PCA Period. The baseline power cost rate established in PSE's 2019 general rate case, Docket UE-190529 ("2019 GRC") went into effect October 15, 2020 and remained the effective rate for the first six months of the 2021 PCA Period, through June 30, 2021. The baseline power cost rate approved in PSE's 2020 power cost only rate case, Docket UE-200980 ("2020 PCORC") went into effect July 1, 2021 and remained the effective rate for the remainder of the 2021 PCA Period. The Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, contains further information regarding the baseline rates in effect for the 2021 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 lead to 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 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 recovered in rates. The costs or benefits of such variances are shared between PSE and customers according to three graduated levels of power cost variance, or 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-recoveries) are shared 50 percent to PSE and 50 percent to customers while benefits (over-recoveries) 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 refund or allows a surcharge. The Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, contains further information regarding accounting for the cumulative balance.

III. 2021 PCA PERIOD POWER COSTS

A <u>PSE's Management of its Power Portfolio and Fuel Supply</u>

Q. What governance does PSE have over power cost management activities and wholesale market transactions?

A. PSE's Energy Supply Management ("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 wholesale markets for power and gas. The ESM department was under my direction for all of the 2021 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 directed by the Director of Enterprise Risk Management.

PSE's Energy Management Committee ("EMC") is composed of five PSE officers and 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 procedures for implementation by PSE staff. PSE's Energy Risk Policy ("Policy") and Energy Supply Transaction & Hedging Procedures Manual ("Procedures") 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. 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. The variable nature of PSE's load combined with variability in output from its resources creates capacity in excess of requirements during many periods of the year. The ESM department maximizes the value of PSE's electric portfolio assets by selling transmission, generation, and natural gas pipeline capacity into the regional markets when it is not needed to meet PSE load. These portfolio optimization activities align with PSE's Policy and Procedures.

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 ESM department does not enter into risk positions for the purpose of earning trading profits. The Policy and Procedures provide guidance and risk management strategies for hedging market price 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. During the Programmatically Managed Hedge period PSE's ESM department executes hedges to systematically reduce PSE's net electric portfolio exposure (including natural gas for power generation) so that, as a month rolls into the Actively Managed Hedge period, 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, the ESM department monitors positions on a daily basis and authorized traders execute transactions to manage exposure within monthly and [redacted] limits established by the EMC.

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 market exposure of all three positions. Spot market exposure is measured by multiplying the net open position, in megawatt hours ("MWh") or million British Thermal Units ("MMBtu"), by a forward 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 fixed-price 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 determines the specific timing of when hedging transactions are entered and decides with whom, among counterparties approved by the ERC department, to execute transactions to manage net exposure, subject to counterparty credit limits.

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 information is used 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 are permitted to transact only within established credit limits.

B <u>PSE's 2021 PCA Period Power Supply Resources</u>

Q. Were there changes to PSE's electric supply resources during the 2021 PCA Period relative to those included in the baseline rate?

A. As noted above, the baseline rate in effect during the 2021 PCA Period reflected the power portfolio from PSE's 2019 GRC during the first six months of the year and the portfolio from PSE's 2020 PCORC during the last six months of the year. PSE's actual 2021 PCA Period power supply portfolio included actual resources, power contracts, and contract rates in effect during 2021. Specifically, relative to resources included in rates, PSE's actual 2021 portfolio included:

1. Different market purchases and sales made in response to changes in load, resource availability, and market heat rates, which guide PSE's decisions of whether to dispatch gas-fired generation or to buy power in the market;

2. A 40 MW hydroelectric power purchase agreement ("PPA") with Energy Keepers, Inc. which began on March 1, 2020 but was not included in PSE's 2019 GRC and therefore not reflected in rates for the first six months of 2021;

3. A 17 MW PPA with Sierra Pacific Industries ("SPI Biomass PPA") which began on January 1, 2021 but was not included in PSE's 2019 GRC and therefore not reflected in rates for the first six months of 2021;

4. A larger share of Wells hydroelectric project output and costs under PSE's long-term PPA with Douglas County Public Utility District ("PUD") which was not included in the forecast for the 2019 GRC and therefore not reflected in rates for the first six months of 2021;

5. A 50 MW transmission contract with Bonneville Power Administration ("BPA") that PSE acquired from Talen Energy which began January 1, 2020 but was not included in the 2019 GRC and therefore not reflected in rates for the first six months of 2021;

6. Extension of a PPA with Douglas County PUD for 5.5 percent of the output from the Wells Hydroelectric Project ("Wells Colville slice"), which began October 1, 2021 but was not included in the 2020 PCORC and therefore not reflected in rates for the last three months of 2021;

7. Termination of a 22 MW PPA with Electron Hydro which was not reflected in the forecast for the 2020 PCORC and therefore the PPA was still included in rates during the last six months of 2021.

Q. Please summarize PSE's actual electric energy supply during the 2021 PCA Period compared to the amounts included in rates.

A. Table 1 below provides a comparison of the generated and purchased energy volumes used to serve load during 2021 relative to the resource volumes included in rates.

Table 1: Actual 2021 Energy Supply Volumes vs Volumes Included in Rates (MWh)

	Actual	Rates	Variance
Coal-fueled generation (Colstrip)	2,576,702	2,274,688	302,014
Natural gas-fueled generation	7,341,076	3,158,924	4,182,152
Long-term contracts (PPAs)	4,211,191	4,210,927	264
Hydro (PSE-owned + Mid-C contracts)	4,416,814	4,092,722	324,093
Wind (PSE-owned)	2,073,012	1,941,927	131,085
Net market purchases & sales	1,667,047	6,399,229	(4,732,182)
Total supply (load, before system losses)	22,285,843	22,078,417	207,426

C <u>PSE's 2021 PCA Period Power Cost Under-Recovery</u>

Q. How did PSE's actual power costs for the 2021 PCA Period compare to power costs recovered through rates?

A. During the 2021 PCA Period, PSE recovered $757.2 million of power costs through the PCA variable baseline rate and incurred actual allowable power costs of $825.2 million. This $68.0 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. The customer share of 2021 PCA Period under-recoveries before interest is $36.7 million.

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

A. Power costs included in rates are estimated for a particular twelve month period, or rate year, that often does not align with the period during which rates are in effect. For example, the rate year for which PSE forecasted power costs in its 2019 GRC was May 2020 through April 2021. Rates established based on this rate year did not go into effect until October 15, 2020 and then remained the effective rates through June 30, 2021. This misalignment between the period for which power costs are estimated to establish rates and the period for which rates are actually in effect creates differences in resource assumptions, market prices, and load that ultimately lead to PCA under or over-recoveries even before accounting for volatility and forecast variances in these same variables. Similarly, the rate year for which power costs were estimated in the 2020 PCORC was June 2021 through May 2022. While resource assumptions, prices, and forecasted load for 2021 were all updated only shortly before rates went into effect for the last half of 2021, rates from the 2020 PCORC did not go into effect until July 2021, a month after the start of the rate year in that case. Rates established in the 2020 PCORC are anticipated to remain in effect through the end of 2022. This means that the effective baseline rate for the last seven months of 2022 will be based on a forecast of 2021 power costs – which is very likely to create additional PCA variances in 2022.

In addition, even if rate year forecast periods and rate effective periods were perfectly aligned, actual costs of power delivered to PSE's system would still differ from those established in rates because actual power costs reflect the realized outcome of multiple power cost variables. These variables include:

(i) customer demand (load),

(ii) the supply of hydroelectric energy,

(iii) output from other variable energy resources such as wind and solar

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

(v) contract rates,

(vi) transmission and natural gas transportation constraints, and

(vii) market energy prices.

Finally, 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 2019 GRC and 2020 PCORC normalized power cost variables by utilizing:

(i) a weather normalized load forecast,

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

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

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

(iv) historical average generator forced outage rates,

(v) gas prices equal to a historical three-month average of forward market prices, and

(vi) model-generated market power prices

Q. What caused the difference between PSE's actual power costs and power costs recovered in rates during the 2021 PCA Period?

A. During the 2021 PCA Period, PSE's total actual allowable power costs were $68.0 million higher than power costs recovered in rates. This under-recovery was the result of actual allowable costs that were $71.7 million higher than costs included in rates offset by baseline rate revenue that was $3.7 million higher than revenue assumed in rates. Higher baseline rate revenue was due to actual delivered load[2] that was 0.9 percent higher than the delivered load forecast used to establish rates.

The $68.0 million total actual PCA under-recovery was due to differences in resources, load, and market prices between the power cost forecasts used to establish rates and actual operations. These differences were primarily the result

[2] Variance in actual delivered load reported here is before removal of Green Direct customer load. Rates established in the 2019 GRC were based on full load so 2021 PCA results include a revenue adjustment to effectively remove the impact of Green Direct load from actual PCA revenue and PCA revenue in rates for the first six months of the year.

of changes to actual resource availability and cost information not being fully reflected in rates, higher actual PSE load than the forecasted load used to establish rates, and wholesale market power and natural gas prices that were consistently higher than the prices used in rates.

Q. Please summarize PSE's actual 2021 power cost variance relative the costs included in rates and the 2021 PCA under-recovery.

A. Table 2 below provides a comparison of 2021 actual 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 $68.0 million total under-recovery and are discussed below.

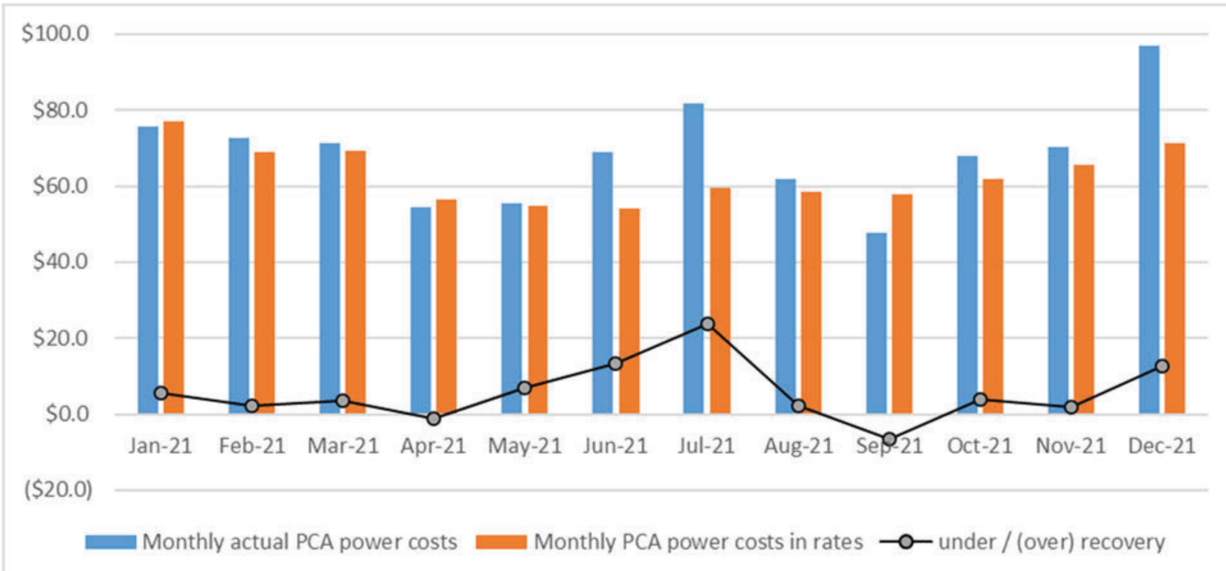
Table 2. Actual 2021 PCA Costs and Revenue vs Amounts in Rates **($ in millions)**

	Actual	**Rates**	**Variance**
Coal fuel	$49.6	$40.2	$9.4
Natural gas fuel and transportation	$183.7	$81.2	$102.5
Long-term contract purchases	$349.7	$341.1	$8.6
Net market purchases & sales	$109.3	$163.2	($54.0)
Transmission	$125.9	$123.8	$2.1
Other PCA items[3]	$7.0	$4.0	$3.0
Total PCA variable cost	$825.2	$753.5	$71.7
PCA revenue from delivered load	($757.2)	($753.5)	($3.7)
2021 PCA under-recovery	$68.0	$0.0	$68.0

[3] Brokerage fees in FERC account 557, Montana Electric Energy Tax, Centralia PPA equity adder, EIM fixed cost adjustment, firm wholesale adjustment, and expected under-recovery due to a flat baseline rate combined with the mid-calendar-year rate change

Figure 1 below shows monthly actual 2021 power costs compared to power costs in rates as well as the monthly actual PCA under or (over) recovery.

Figure 1. Actual 2021 PCA Costs vs Costs in Rates and Monthly Actual PCA Under / (Over) Recovery ($ in millions)



Q. How did differences between PSE's actual resource portfolio and resource assumptions used to establish rates impact the 2021 PCA under-recovery?

A. The power cost baseline included in rates for the first half of 2021 was established in PSE's 2019 GRC. Forecasted power costs in that case were for the rate year ending April 2021 and based on resource and portfolio assumptions as of 12/5/2019. This difference in the forecast period used to establish rates and the actual rate effective period meant that for the first half of 2021 the power cost baseline rate did not include current information for PSE's resource portfolio, contract rates, load forecast, or market prices.

More specifically, power costs in rates for the first half of 2021 did not include new PPAs, changes to the prices of existing PPAs, changes to the cost and PSE's share of output from its Mid-Columbia hydroelectric contracts,[4] or updates to the cost of PSE's transmission and gas-transportation contracts.

The baseline rate changed on July 1, 2021 as an outcome of the 2020 power cost only rate case ("PCORC"). Similar timing differences between actual resources and gas prices and those included in the forecast used to set the baseline rate contributed to under-recoveries in the second half of 2021. The 3-year extension of the Wells Colville slice contract, which allows PSE to receive a 5.5 percent slice of the output from the Wells Project beginning in October 2021, was not included in the PCORC forecast used to set the baseline rate because the contract had not been executed at the time PSE prepared its forecast in that case. Rates established in the 2020 PCORC also did not reflect termination of PSE's PPA with Electron Hydro, the actual increase to BPA transmission rates, or tariff rate updates for PSE's natural gas pipeline contracts.

Overall, differences in portfolio resource assumptions embedded in rates relative to actual 2021 portfolio resources and contract rates—which were unrelated to changes in load, variability in resource output, or commodity prices—contributed an estimated [redacted] to PSE's 2021 PCA under-recovery, or 38.8 percent of the total under-recovery. Table 3 below summarizes the impact of individual

[4] Particularly PSE's contract with Douglas County PUD for output from the Wells hydroelectric project. PSE's share of output and cost under this contract changes each year and the actual % share in 2021 was significantly higher than the % share included in rates from the 2019 GRC.

items discussed above. These are variances that the PCA mechanism was not specifically intended to address. The overview of the PCA in both the original settlement stipulation and the revised settlement stipulation states that "the factors influencing the variability of power costs included in the mechanism are primarily weather or market related."[5]

PSE's remaining 2021 under-recovery was primarily attributable to higher actual 2021 load than the load forecasts used in rates combined with market prices that were higher in reality than the prices assumed in rates.

Table 3: Estimated Impact of Resource Information Not Updated in Rates ($ in thousands)

	2019 GRC rates	2020 PCORC rates	Total impact on 2021 under-recovery
Mid-C hydro contract costs & share of output	$15,289	($1,077)	$14,212
New PPAs (Energy Keepers, SPI, Wells Colville)	$6,731	$563	$7,294
Termination of Electron hydro PPA	$0	($2,836)	($2,836)
Transmission and gas pipeline contracts	$5,574	$2,182	$7,756
Net cost not included in rates	$27,594	($1,169)	$26,426

D 2021 PCA Variance discussion

Market prices

[5] Dockets UE-130583, UE-130617 and UE-131099, Attachment A to Settlement Stipulation, page 1 at A.1; Dockets UE-011570 and UG-011571, Exh. A to Settlement Stipulation, page 1 at B2.

Q. How did actual 2021 market energy prices compare to the prices assumed in rates?

A. Actual market prices for both power and natural gas during 2021 were significantly higher than prices assumed in rates from the 2019 GRC and 2020 PCORC. Abnormally cold conditions fueled market price spikes in February and December. Warmer-than-normal conditions throughout the summer were punctuated by record-setting Pacific Northwest temperatures in June and an abnormally hot September, particularly in California and the desert Southwest. Each of these market events is described in more detail in Section IV below. While abnormal weather conditions were a key contributor to high market power and gas prices in 2021, variances between actual prices and those included in rates were also the result of timing differences between when rates were established and the actual rate effective period combined with longer-term trends in commodity markets and the regional resource mix. Relatively high actual market prices in 2021 drove variances in the cost of market purchases, the cost of fuel for power generation, and changes in the dispatch of PSE's coal- and natural gas-fired resources relative to the forecasts used to establish rates. Figure 2 below compares 2021 actual natural gas prices to the gas prices assumed in rates. Figure 3 compares actual 2021 power prices to the power prices assumed in rates.

Figure 2. 2021 actual Sumas gas prices vs Sumas gas prices in rates ($/MMBtu)

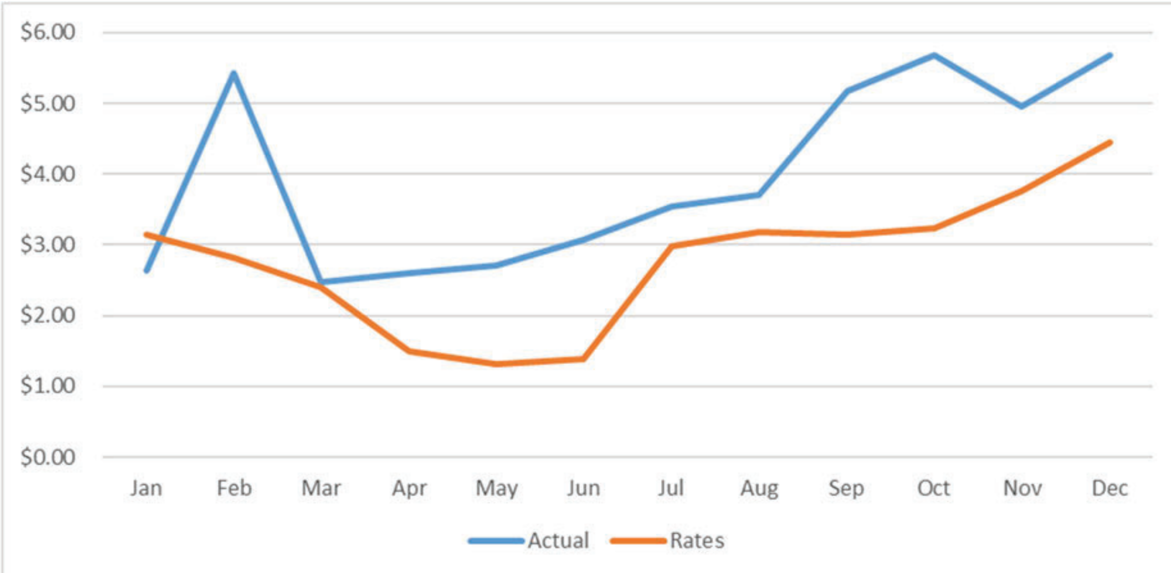
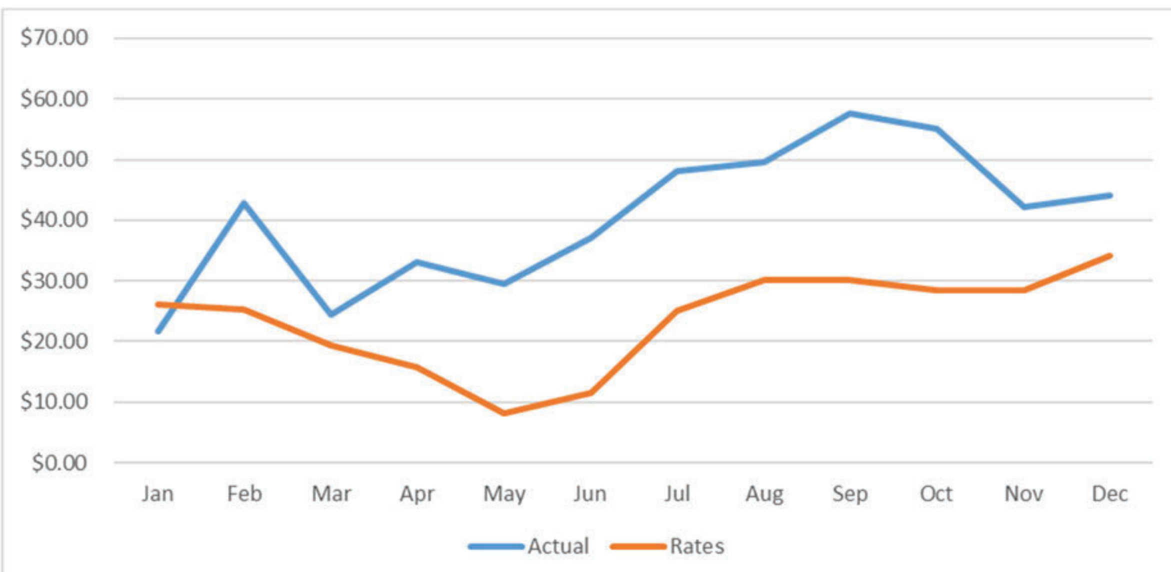


Figure 3. 2021 actual Mid-C power prices vs Mid-C power prices in rates ($/MWh)



Load

Q. How did variances in actual load relative to the forecast in rates impact PSE's 2021 PCA Period under-recovery?

A. Actual PSE load in 2021 was approximately 0.9 percent higher than the load forecasts used to establish rates in effect during 2021. These higher actual loads had two different, partially off-setting impacts on the 2021 PCA under-recovery. First, higher load increases PSE's actual power costs because it increases the amount of energy that must be purchased in the wholesale markets or decreases the amount of surplus energy that can be sold in the wholesale markets. Second, higher load increases retail sales (delivered load) which increases revenue collected via the power cost baseline rate. During 2021 baseline rate revenue was $3.7 million higher than revenue included in rates due to higher delivered loads. This higher revenue, however, was not sufficient to off-set the cost of additional market purchases (or fewer market sales) needed to serve the higher load. Actual load that was higher than the load forecasts included in rates increased power costs approximately [redacted] million[6] during 2021.

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[6] Estimate based on actual flat Mid-C monthly market power prices and monthly load variances. Higher loads frequently coincided with periods of higher prices at the daily or hourly level, so this is likely to be a low estimate.

Market purchases and sales

Q. How did market purchases and sales during the 2021 PCA Period compare to amounts in rates?

A. In 2021 PSE's actual electric market purchases were 1.7 million MWh more than actual market sales. The forecasts in rates for 2021 estimated PSE would be a net purchaser of 6.4 million MWh. Lower actual net market purchase volume for the year was the result of increased generation from PSE's coal- and natural gas-fired resources, more generation from PSE's Mid-Columbia hydroelectric resources, and higher output from PSE's wind facilities.

While the actual volume of net market purchases in 2021 was 74.0 percent below the forecasts in rates for 2021, the reduction to the cost of these purchases was proportionally less due to higher market power prices. The actual cost of PSE's net market purchases and sales in 2021 was 33.1 percent, or $54.0 million below the cost included in rates. The average cost of actual market purchases in 2021 was $47.73 per MWh compared to only $26.05 per MWh included in rates.

Colstrip

Q. How did actual coal fuel costs compare to costs in rates during the 2021 PCA Period?

A. Actual fuel cost for PSE's Colstrip Units 3&4 was $9.4 million higher than the cost included in rates for 2021. This cost variance was primarily the result of increased generation driven by higher actual power prices than assumed in rates.

Per-unit coal supply costs are relatively fixed, so higher power prices made it more economic to run the plant at higher output levels. Actual Colstrip output in 2021 was 13.3 percent, or 302,014 MWh, higher than generation included in rates. In addition to higher energy volumes, a portion of the 2021 Colstrip fuel cost variance is attributable to higher actual per unit coal costs than assumed in rates. 2021 actual Colstrip unit fuel cost of $19.21 per MWh was higher than the $17.65 per MWh included in rates for 2021. Higher actual unit fuel costs relative to unit costs in rates were primarily due a new coal supply contract which began January 1, 2020 but was not included in the rate year forecast from PSE's 2019 GRC.

<u>Natural gas generation and transportation</u>

Q. Why were actual 2021 natural gas fuel and transportation costs higher than the costs included in rates?

A. Total actual natural gas fuel and transportation costs during 2021 were 126.2 percent, or $102.5 million higher than costs included in rates. These higher costs were the result of increased generation, higher gas prices, and higher costs of gas transportation contracts offset by gains from financial gas hedges and higher revenue from pipeline optimization transactions.

Generation from PSE's natural gas-fired resources was 4.2 million MWh, or more than 132.4 percent higher than generation included in rates for 2021. This increased output relative to the forecasts in rates was the result of higher market heat rates, a measure of the relative price of natural gas vs. power, which made it more economical to run the facilities more often. Figure 4 and Figure 5 below show PSE's actual natural gas-fired generation and market heat rates relative to forecasts in rates for 2021.

Figure 4. 2021 actual gas-fired generation vs gas-fired generation in rates (MWh)

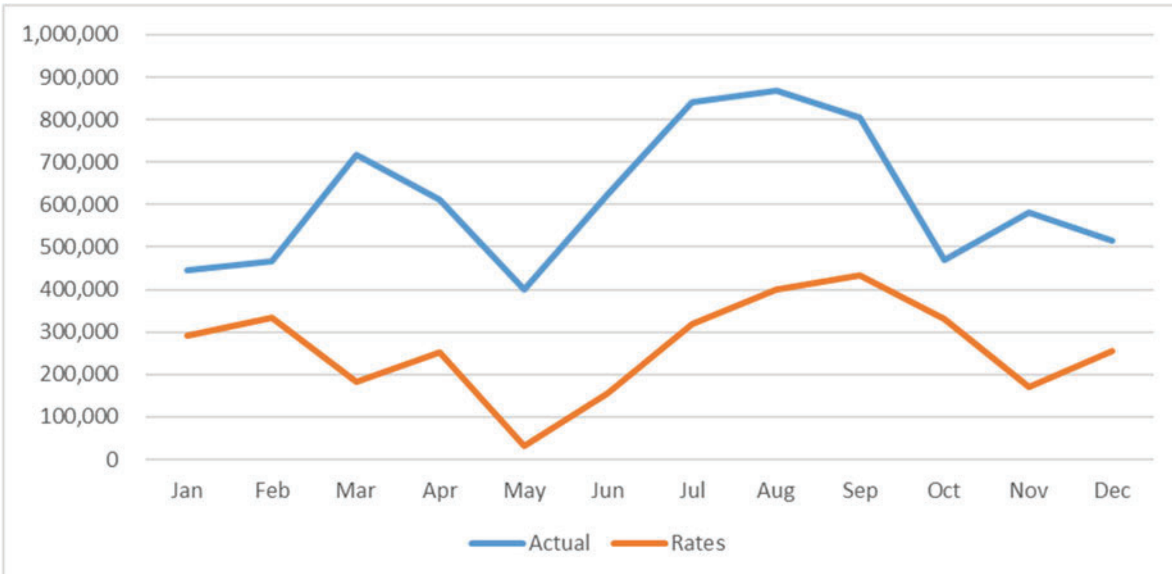
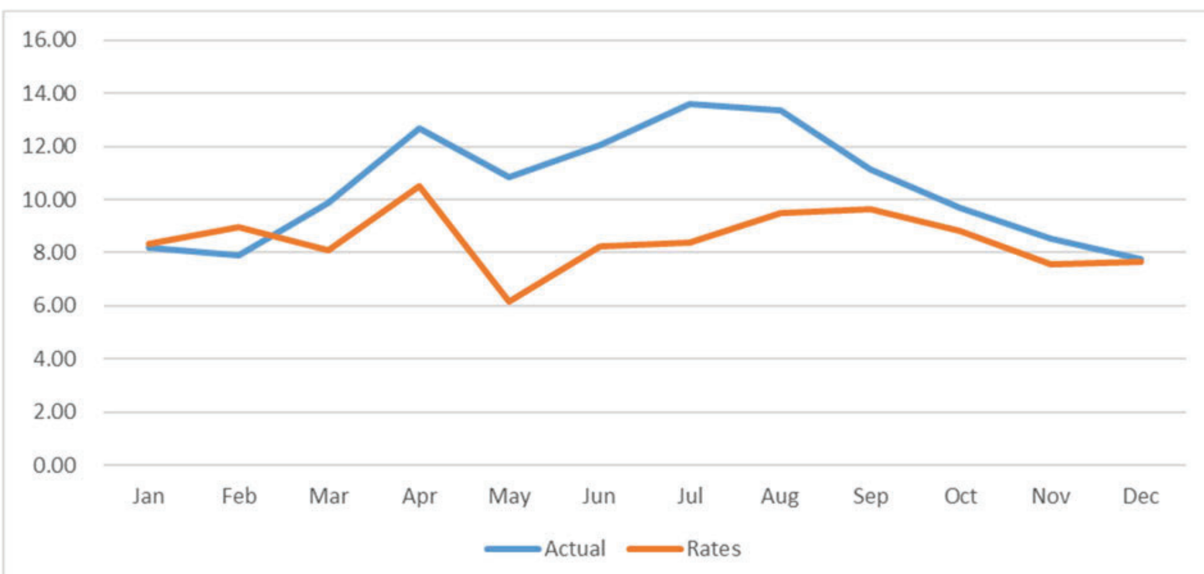


Figure 5. 2021 actual flat market heat rates vs flat market heat rates assumed in rates (MMBtu/MWh)



While PSE's gas-fired resources generated more than forecasted in rates for 2021, higher natural gas prices meant that the average cost of fuel for these resources was also higher than assumed in rates. The average actual unit fuel cost for PSE's gas-fired resources in 2021 was $28.89 per MWh compared to $24.49 per MWh included in rates, before variances in fixed gas transportation costs and benefits from gas hedges and pipeline optimization. Actual fixed gas transportation costs in 2021 were $5.6 million higher than the fixed transportation costs included in rates due to pipeline tariff rate increases that were not reflected in rates established in the 2019 GRC and 2020 PCORC. The impact to power costs of higher fuel prices and higher transportation cost was offset by gains from financial gas hedges and net revenue from sales of gas utilizing surplus pipeline capacity (pipeline optimization). Gains on financial gas hedges in 2021 were $39.8 million, or $25.6 million more than included in rates. Pipeline optimization net revenue in 2021 was $49.0 million, or $12.3 million more than included in rates.

Long-term contracts (Power Purchase Agreements)

Q. How did long term power contracts impact costs during the 2021 PCA Period?

A. In 2021 PSE received 4,211,191 MWh from its long-term contracts (excluding Mid-Columbia hydroelectric PPAs), which was nearly the same volume included in rates during 2021 (4,210,927 MWh). The combined actual cost of these contracts was $231.9 million, 2.7 percent lower than the cost included in rates.

These overall results are the net outcome of several offsetting variances in individual PPA volumes and prices. As discussed earlier, rates in effect during calendar year 2021 did not reflect fully include the Energy Keepers PPA, the SPI Biomass PPA, termination of the Electron Hydro PPA, or changes to the price of existing PPAs. The estimated impact to PSE's 2021 under-recovery, $3.9 million, was offset by changes in the energy actually received from contracts with variable output. Actual energy from PSE's Schedule 91 contracts—contracts with small wind, solar, hydro, and bio-fueled generators—was 45.5 percent below the energy included in rates for these facilities. The price of these Schedule 91 PPAs in 2021 was higher than market energy prices, so lower volumes reduced PSE's actual power costs.

Q. Why were Mid-C hydroelectric contract costs higher than the amounts included in rates?

A. The variance in the cost of PSE's Mid-C hydroelectric contracts in 2021 relative to the cost in rates was the result of changes to PSE's share of output under its PPA with Douglas PUD for output from the Wells Project, higher actual costs based on updated budgets from Chelan and Grant PUDs, and the new Wells Colville contract that was not included in rates for the last three months of 2021.

PSE wind and hydro

Q. How did output from PSE-owned wind and hydro resources affect power costs in 2021?

A. There are no fuel or purchased power costs associated with PSE-owned wind and hydroelectric assets, so there are no direct cost variances associated with these resources in 2021 actual PCA results relative to costs in rates. Instead, variances in the output of PSE's wind and hydroelectric resources drive changes in PSE's market purchases and sales relative to the forecasts in rates—each MWh that is not generated by a wind or hydro resource requires PSE to purchase (or not sell) one MWh in the market.

Actual output from PSE's wind resources in 2021 was [redacted] MWh above wind generation included in rates for 2021. This generation variance relative to rates decreased the net cost of PSE's actual 2021 market purchases and sales approximately [redacted] (based on actual monthly flat Mid-C power prices).

Actual output from PSE-owned hydro resources in 2021 was [redacted] MWh higher than generation included in rates for 2021. This generation variance relative to rates decreased the net cost of PSE's actual 2021 market purchases and sales approximately [redacted] (based on monthly actual flat Mid-C power prices).

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Transmission

Q. Why did actual transmission expense vary from the amount in rates during the 2021 PCA Period?

A. During the 2021 PCA Period, the total net cost of purchased transmission was $2.1 million higher than the costs included in rates. These higher costs were the result of a transmission contract costs that were $3.0 million higher than the amount in rates offset by revenue from transmission reassignments (short-term sales of surplus transmission capacity) that was $0.9 million higher than the amount in rates. Transmission contract costs in 2021 were higher than the amount in rates primarily due to a BPA transmission rate increase effective October 1, 2021 that was not fully included in rates established in the 2020 PCORC. The addition of a 50 MW BPA transmission contract that was executed in July 2019 and effective in January 2020 but not included in rates until July 2021 also contributed to higher transmission costs during the first six months of the year.

IV. 2021 MARKET EVENTS

Q. Were there any notable market events that impacted PSE's power supply operations in 2021?

A. Yes. During 2021 four separate periods of extreme weather caused extraordinary volatility in power and gas market prices and increased PSE electric demand, prompting concerns about the availability of reliable power and natural gas supply. Each of these events is notable from a power supply reliability perspective and helps illustrate how volatility in commodity prices is often the result of a combination of factors impacting supply and demand both in the Pacific Northwest and throughout the wider Western grid area. These events also highlight the risks inherent in relying on wholesale markets for energy supply during peak load periods. In terms of PSE's overall 2021 PCA under-recovery, however, the impact of these short-duration and well managed events was masked by the more significant impacts of outdated resource assumptions in rates, average overall higher loads (as opposed to very high, but brief peak loads), and consistently higher market commodity prices discussed earlier in my testimony. For example, referring back to Figure 1, PSE's highest monthly under-recovery for the year occurred in July, a month that did not include a specific market event. Similarly, September did include such an event and PSE actually over-recovered power costs in September.

Q. Please describe the February 2021 market event?

A. From February 12 to February 14, 2021, average temperatures were 13 degrees Fahrenheit below 30-year historical averages. These freezing temperatures combined with a snow storm that included accumulated totals in excess of 12 inches in Seattle –the first time that happened since 1972. The combined snow total ranked 15th highest for a two consecutive day period in over 125 years according to the Seattle National Weather Service.[7] Average actual PSE electric load between February 12 and 18 came in approximately 16 percent higher than normal for that time of year. Over these same five days Sumas gas prices

[7] https://mynorthwest.com/2592895/puget-sound-region-record-setting-snow-february-2021/

averaged $12.42 per MMBtu, more than double the 10-year average February price and a 440 percent increase relative to the $2.82 per MMBtu February Sumas price included in rates from the 2019 GRC. Average daily on-peak power prices averaged $114.90 per MWh and off-peak power averaged $76.66 per MWh, compared to average February prices of $27.06 per MWh on-peak and $22.83 per MWh off-peak used in rates from the 2019 GRC.

Q. Did factors other than cold weather impact energy supply conditions and wholesale energy markets during the February 2021 event?

A. Yes. Between February 7 and February 13 a forced outage of a compressor on the Westcoast pipeline limited the amount of gas that could be transported to Sumas from northern British Columbia. This limitation on gas imports exacerbated already volatile gas prices and concerns about supply reliability during the event. Further, three transmission lines carrying power into the Pacific Northwest –the DC South to North line and AC South to North line carrying power from California and the NI West North to South line carrying power from British Columbia –were at reduced capacity during the February 2021 cold weather event. The de-rates on these three lines did not have a direct impact on PSE’s ability to procure power supply to meet peak load, but they nonetheless contributed to the tight supply/demand balance in the region during this period and resulting high market power prices.

Q. How did PSE manage its power supply operations during the February event?

A. On February 12, 2021 PSE's ESM department updated its power supply monitoring status from green (normal) to yellow, indicating that generation or transmission constraints could potentially limit wholesale power supply or that cash markets were demonstrating material price volatility. The yellow status includes an order to staff at PSE generation facilities to refrain from any work that could jeopardize the availability of generation and cancels transmission work that could affect delivery of energy supply to PSE's system. PSE's ESM department managed the price volatility and associated heightened reliability risk by economically dispatching and running gas-fired units, running hydroelectric plants more than planned by drafting reservoirs below normal elevations, and executing short term market purchases and sales to meet demand. For example, PSE purchased 950 MW of on-peak power in the day-ahead market for February 14. These day-ahead purchases limited financial and reliability risk associated with the potential for unavailable and/or very expensive energy in the real time market.

Q. Please describe the June 2021 market event?

A. As of Friday, June 25, 2021, forecasts for the next five days indicated above normal temperatures in the Pacific Northwest region by at least 15 degrees Fahrenheit. Based on these temperature forecasts, PSE's ESM department updated its power supply monitoring status from green to yellow. Starting June

26, record daily high temperatures were set on three consecutive days, with June 28 breaking the highest temperature ever recorded at Seattle-Tacoma International Airport at 108 degrees Fahrenheit.[8] This made it the hottest day since 1945 when official temperatures started to be measured at Seattle-Tacoma Airport. On June 27, PSE updated its power supply monitoring status to from yellow to red, reflecting the risk that PSE might not have sufficient supply to meet load if planned supply resources were not delivered. Energy supply monitoring status red indicates that material power supply constraints exist or markets are experiencing material volatility such that a Level 1 Energy Emergency Alert may be called by the regional reliability coordinator.

Actual PSE electric load between June 25 and June 29 was 38 percent higher than normal for that time of year. On June 28, PSE recorded its highest summer peak load ever at 4,036 MW during hour ending 17. This peak was 15 percent higher than the previous summer peak load of 3,508 MW set in July 2009.

High temperatures and associated demand drove market power and gas prices well above normal levels and the prices included in PSE's rate year forecast during the event. The day-ahead Mid-C on peak price for June 28 rose to $334.22 per MWh and off-peak power traded at $51.17 per MWh. The rates in effect for June from PSE's 2019 GRC included power prices of $12.25 per MWh on-peak and $10.31 per MWh off-peak. The Sumas gas price on June 28 was $3.39 per

[8] https://www.seattletimes.com/seattle-news/weather/seattle-already-set-record-high-temperatures-sunday-mondays-forecast-is-unheard-of/

MMBtu, well above the $1.38 per MMBtu June Sumas gas price included in rates from PSE's 2019 GRC.

Q. Did factors other than hot weather impact energy supply conditions and wholesale energy markets during the June 2021 event?

A. Yes. Two large transmission lines connecting the Pacific Northwest to California were de-rated during the hot weather event, which limited imports into the region and put further upward pressure on power prices. During the June 25 through June 28 period, the DC South to North line was limited to only 47 percent of full capacity, while capacity on the AC South to North line was limited to 82 percent. These two de-rates reduced PSE's firm transmission capacity at the California-Oregon Intertie from 300 MW to only 83 MW during the June market event. The specific impact of these de-rates on PSE's ability to secure power supplies during the event was not significant as PSE was already not relying on imports from California in its day-ahead plans due to the risk that the California Independent System Operator could curtail exports in response to its own reliability concerns.

Q. How did PSE manage its power supply operations during the June event?

A. PSE's thermal and hydro generation ran above historical averages with capacity factors of 85 percent or higher. High availability of thermal resources, including the return of Colstrip Unit 3 on June 26 from a planned maintenance outage made this possible. Output from PSE's wind generation resources averaged only about 15 MW, or just under 4 percent of full capacity during the five-day event. To meet its peak load on June 28, PSE relied on just over 1,500 MW of bilateral energy purchases at the Mid-C trading hub. Nearly half (48 percent) of this total market supply was obtained via purchases in the day-ahead and hour-ahead bilateral markets which, fortunately, remained liquid enough for PSE to acquire the energy needed to meet demand and maintain reliable service.

Q. Please describe the September 2021 market event.

A. Between September 8 and September 10, 2021 , the Desert Southwest and California saw persistent temperatures near 100 degrees Fahrenheit. During this same time period, the temperatures in the PNW were above 30-year historical averages, though not as hot as the Southwest region. These higher than normal temperatures drove electric loads within PSE's service territory above normal loads for the month of September. The overall supply/demand balance in the Pacific Northwest was tightened as high power prices in California and the Southwest incentivized exports to those areas. In turn, prices at the Mid-C market hub increased in order to prevent needed power from moving south. Day-ahead prices at Mid-C rose to nearly $300 per MWh. PSE's real-time desk saw hour-ahead bilateral prices at Mid-C as high as $900 per MWh on September 9, which was the highest price PSE traded at the Mid-C bilateral hub in 2021. PSE's power supply monitoring status was updated from green to yellow on September 8 due to elevated risk in the real time market if planned resources were not delivered.

Q. Did factors other than hot weather impact energy supply conditions and wholesale energy markets during the September 2021 event?

A. Yes. High temperatures throughout the western grid area coincided with low hydro and wind generation and reduced transmission capacity into the Pacific Northwest. High market prices in the Desert Southwest were exacerbated by gas supply constraints resulting from a rupture of the El Paso Pipeline in August.

Q. Please describe December 2021 market event.

A. Prolonged cold swept through the PNW from December 23 to 29, 2021, with temperatures averaging 10 degrees Fahrenheit below normal. PSE updated its energy supply monitoring status from green to yellow on December 23 in response to forecasted cold temperatures and anticipated high demand. Cold temperatures propelled gas and power demand much higher than normal levels, with power peaking at 4,743 MW on December 27. High output from hydroelectric plants throughout the region mitigated upward pressure on power prices and allowed PSE to rely on hydro generation to help meet demand throughout the period in lieu of more expensive gas-fired generators.

V. CONCLUSION

Q. Were PSE's power costs during the 2021 PCA Period prudently incurred?

A. Yes; PSE's power costs for the 2021 PCA Period were prudently incurred. PSE's management of its power costs during the 2021 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 2021 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.