

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

In the Matter of

PACIFIC POWER & LIGHT
COMPANY,

2018 Power Cost Adjustment Mechanism

Docket UE- _____

**PACIFIC POWER & LIGHT COMPANY
DIRECT TESTIMONY OF MICHAEL G. WILDING**

June 2019

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ATTACHED EXHIBITS

Exhibit No. MGW-2: 2018 PCAM Deferral Calculation

1 **Q. Please state your name, business address, and present position with Pacific**
2 **Power & Light Company (Pacific Power), a division of PacifiCorp.**

3 A. My name is Michael G. Wilding. My business address is 825 NE Multnomah Street,
4 Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs and
5 Regulatory Policy.

6 **QUALIFICATIONS**

7 **Q. Briefly describe your education and professional experience.**

8 A. I received a Master of Accounting from Weber State University and a Bachelor of
9 Science degree in accounting from Utah State University. I am a Certified Public
10 Accountant licensed in the state of Utah. During my tenure at the company, I have
11 worked on various regulatory projects including general rate cases, the multi-state
12 protocol, and net power cost filings. I have been employed by the company since
13 2014.

14 **Q. Have you testified in previous regulatory proceedings?**

15 A. Yes. I have filed testimony in proceedings before the public utility commissions in
16 Washington, Oregon, California, Utah, Wyoming, and Idaho.

17 **PURPOSE OF TESTIMONY**

18 **Q. What is the purpose of your testimony in this proceeding?**

19 A. My testimony presents and supports the company's calculation of the Power Cost
20 Adjustment Mechanism (PCAM) for the 12-month period from January 1, 2018,
21 through December 31, 2018 (Deferral Period). More specifically, I provide the
22 following:

- 1 • Background on the PCAM and an accounting of how the PCAM balance was
- 2 calculated for the Deferral Period;
- 3 • Discussion of the main differences between adjusted actual net power costs
- 4 (Actual NPC) and net power costs in rates (Base NPC), both allocated on a
- 5 West Control Area Inter-Jurisdictional Allocation Methodology (WCA) basis;
- 6 • Discussion of the Colstrip Unit 4 outage that occurred near the end of June
- 7 2018; and,
- 8 • Discussion about the company's participation in the energy imbalance market
- 9 (EIM) with the California Independent System Operator (CAISO) and the
- 10 benefits from EIM that are passed through to customers.

11 **Q. Are additional witnesses presenting testimony specifically for the PCAM and**
12 **Tariff Schedule 97 in this case?**

13 A. No. Since the cumulative PCAM deferral balancing account does not exceed the
14 surcharge or credit threshold of \$17 million, there are no proposed changes to Tariff
15 Schedule 97. The company's PCAM deferral balance triggered a rate change in
16 2018. As a result, the current Schedule 97 is set at a rate to credit customers
17 approximately \$17.9 million over a 12-month period in compliance with Order 02 in
18 Docket UE-180494. That surcredit will expire on or around October 31, 2019.

19 **SUMMARY OF THE PCAM DEFERRAL CALCULATION**

20 **Q. Please briefly describe the company's PCAM authorized by the Washington**
21 **Utilities and Transportation Commission (Commission).**

22 A. The Commission's Order 09 in Docket UE-140762 approved the PCAM to allow the
23 company to track unexpected variations in power costs in the PCAM deferral

1 account. If the cumulative positive or negative balance in the PCAM deferral
2 account, including monthly interest, exceeds \$17 million either a surcharge or sur-
3 credit is triggered.

4 **Q. Please summarize the company's calculation of the PCAM deferral for the**
5 **Deferral Period.**

6 A. For the Deferral Period the cumulative PCAM differential was an approximate
7 \$12.6 million credit before application of the deadband and asymmetrical sharing
8 bands. After application of the deadband and asymmetrical sharing bands, the filing
9 results in a deferral credit of approximately \$6.9 million, including interest.

10 **Q. Have you provided detailed support for the calculation of the PCAM balance**
11 **with your testimony?**

12 A. Yes. Exhibit No. MGW-2 includes a detailed calculation of the company's 2018
13 PCAM deferral on a monthly basis. Detailed confidential workpapers supporting
14 Exhibit No. MGW-2 are provided separately.

15 2018 PCAM CALCULATION

16 **Q. Please describe the company's calculation of the PCAM deferral for the Deferral**
17 **Period.**

18 A. As previously noted, the PCAM deferral is calculated on a monthly basis as the
19 difference between Base NPC collected through general rates and Actual NPC,
20 including actual non-NPC EIM costs. The accrued PCAM variance is subject to the
21 following parameters:

- 22 • Symmetrical Deadband: Any PCAM difference between negative \$4 million
23 and positive \$4 million will be absorbed by the company.
- 24 • Asymmetrical sharing of the PCAM difference as follows:

- 1 ○ Between \$4 and \$10 million; shared 50 percent by customers and
- 2 50 percent by the company;
- 3 ○ Greater than \$10 million; shared 90 percent by customers and
- 4 10 percent by the company;
- 5 ○ Between -\$4 and -\$10 million; shared 75 percent by customers and
- 6 25 percent by the company; and
- 7 ○ Less than -\$10 million; shared 90 percent by customers and 10 percent
- 8 by the company.

- 9 • Amortization of Deferral: The amortization of PCAM variances are deferred
- 10 until the balance of the deferral balancing account results in either a surcharge
- 11 or credit greater than \$17 million.

12 For the Deferral Period, the PCAM differential was approximately a \$12.6 million

13 credit. After application of the deadband and asymmetrical sharing band, the

14 company is seeking approval to credit the PCAM balancing account with

15 approximately \$6.9 million including interest. A summary of the deferral calculation

16 is shown in Table 1.

Table 1
Summary of PCAM Account Balance

<u>Calendar Year 2018 PCAM Deferral</u>	
Actual PCAM Costs (\$/MWh)	\$ 28.58
Base PCAM Costs (\$/MWh)	31.76
PCAM Cost Differential (\$/MWh)	<u>(3.18)</u>
Washington Sales (MWh)	3,949,116
Total PCAM Differential*	\$ (12,576,665)
Total Deferrable ABOVE Deadband	-
Total Deferrable BELOW Deadband	(8,576,665)
Washington Deferral after Sharing	(6,818,999)
Interest Accrued through December 31, 2018	(94,592)
Requested PCAM Recovery	<u><u>\$ (6,913,591)</u></u>
* Calculated monthly	

1 **Q. How is the PCAM differential calculated on a monthly basis?**

2 A. The PCAM differential is calculated by subtracting the NPC collected in base rates
3 from the PCAM Adjusted Actual Costs as shown in the formula below:

$$\text{PCAMC} - (\text{Base NPC}_{\$/\text{MWh}} \times \text{Actual Sales}) = \text{PCAM Differential}$$

Where:

PCAMC - Adjusted actual WCA NPC costs allocated to Washington using allocation factors calculated with actual jurisdictional load plus Washington allocated actual non-NPC EIM costs

Base NPC $_{\$/\text{MWh}}$ - Base NPC unit cost; calculated by dividing Washington-allocated NPC as established in a rate proceeding by the Washington sales-at-meter used to set rates in the rate proceeding

Actual Sales - Actual Washington retail sales at the meter

4 The cumulative PCAM variance is first compared against the symmetrical
5 deadband. Cumulative amounts in excess of the symmetrical deadband are then
6 subject to the sharing bands. The customer portion of the PCAM variance is tracked
7 in the deferral balancing account and monthly balances accrue interest at the current
8 Federal Energy Regulatory Commission (FERC) interest rate. A rate change is
9 triggered when the customer surcharge or credit exceeds \$17 million.

10 **Q. What were the total-company adjusted Actual NPC for the Deferral Period and
11 how were they determined?**

12 A. The total-company adjusted Actual NPC in the Deferral Period were approximately
13 \$498 million on a WCA basis. This amount captures all components of NPC as
14 defined in the company's general rate case proceedings and modeled by the
15 company's Generation and Regulation Initiative Decision Tool (GRID) model.
16 Booked NPC are adjusted to reflect a balanced WCA consistent with the methodology

1 used in Docket UE-140762. Specifically, it includes amounts booked to the following
2 FERC accounts:

3 Account 447 - Sales for resale, excluding on-system wholesale sales and other
4 revenues that are not modeled in GRID;

5 Account 501 - Fuel, steam generation; excluding fuel handling, start-up fuel
6 (gas and diesel fuel, residual disposal) and other costs that are
7 not modeled in GRID;

8 Account 503 - Steam from other sources;

9 Account 547 - Fuel, other generation;

10 Account 555 - Purchased power, excluding the Bonneville Power
11 Administration (BPA) residential exchange credit pass-through
12 if applicable; and

13 Account 565 - Transmission of electricity by others.

14 **Q. What adjustments are made to Actual NPC and why are they needed?**

15 A. The company adjusts Actual NPC to reflect the ratemaking treatment of several items,
16 including:

- 17 • out of period accounting entries booked in the Deferral Period that relate to
18 operations before implementation of the PCAM on April 1, 2015;
19 • reductions to coal costs for legal fees related to fines and citations; and
20 • revenue from a contract related to the Leaning Juniper wind resource.

21 **Q. Please state the amount of the adjusted Actual NPC that were allocated to
22 Washington and describe how the amount was calculated.**

23 A. Washington-allocated Actual NPC were approximately \$112 million during the

1 Deferral Period. To arrive at this value, the company applied the allocation
2 methodology approved by the Commission using actual allocation factors from
3 calendar year 2018.

4 **Q. Please summarize the calculation of the Washington-Allocated Actual Non-NPC**
5 **EIM Costs.**

6 A. The company has included in the PCAM actual non-NPC EIM costs of \$0.4 million
7 that are not otherwise included in NPC. These EIM costs include the return on rate
8 base, ongoing operations and maintenance expense, and depreciation expense. This
9 treatment was approved by the Commission to match recovery of EIM costs and
10 benefits.¹ As described in more detail later on in my testimony, the EIM provides
11 benefits to customers in the form of reduced Actual NPC.

12 **Q. How much of Base PCAM costs did the company collect from Washington**
13 **customers during the Deferral Period?**

14 A. During the Deferral Period, the company received approximately \$125 million in
15 Base PCAM revenue from Washington customers, approximately \$12.6 million more
16 than Washington-allocated Actual NPC and EIM Costs.

17 **Q. What was the total amount of the deferral over the Deferral Period?**

18 A. After application of the deadband and asymmetrical sharing band, the deferral was
19 approximately \$6.9 million credit including interest, as shown in Table 1.

20 **Q. Please describe how the interest on the PCAM deferral balance was determined.**

21 A. Interest is accrued monthly on the PCAM deferral balance at the FERC interest rates
22 that are published quarterly. Over the Deferral Period, the PCAM balance accrued

¹ *Wash. Utils and Transp. Comm'n v. PacifiCorp*, Docket UE-152253, Order 12 at 74 (September 1, 2016).

1 \$0.1 million of interest refundable to customers.

2 **Q. Is the company requesting a rate change with this filing?**

3 A. No. Since the PCAM balancing account does not exceed the customer surcharge or
4 credit threshold of \$17 million, the company is requesting the balance be updated to
5 include the current year deferral. See Table 2 for a summary of the deferred
6 balancing account.

**Table 2
Deferred Balancing Account**

	Washington Customers
Balancing Account Activity	
Beginning Deferral Balance	\$ -
2018 PCAM Deferral	(6,818,999)
Interest	<u>(94,592)</u>
Activity Through December 31, 2018	<u>(6,913,591)</u>
December 31, 2018 Ending Balance	<u><u>\$ (6,913,591)</u></u>

7 **DIFFERENCES IN NPC**

8 **Q. On a WCA basis, what was the difference between Actual NPC and Base NPC**
9 **for the Deferral Period?**

10 A. Actual NPC for the Deferral Period were \$498 million, less than Base NPC for the
11 Deferral Period by approximately \$53 million. Table 3 below provides a high level
12 summary of the difference between the Base NPC and Actual NPC by category on a
13 WCA basis.

Table 3
Net Power Cost Reconciliation (\$millions)

Base NPC	\$	551
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		21
Purchased Power Expense		(27)
Coal Fuel Expense		(16)
Natural Gas Expense		(37)
Wheeling and Other Expense		6
Total Increase/(Decrease)		(53)
Adjusted Actual NPC	\$	498

1 **Q. Please describe the Base NPC the company used to calculate the NPC component**
2 **of the PCAM deferral.**

3 A. The Base NPC of \$551 million was established in Docket UE-140762 using a test
4 period of April 2015 through March 2016.

5 **Q. Please describe the differences between Actual NPC and Base NPC.**

6 A. Actual NPC were lower than Base NPC due to a \$37 million reduction in natural gas
7 fuel expense, \$27 million reduction in purchased power expense, and a \$16 million
8 reduction in coal fuel expense. These reduced expenses were partially offset by a
9 \$21 million decrease in wholesale sales revenues and a \$6 million increase in
10 wheeling and other expenses.

11 **Q. Please explain the changes in wholesale sales revenue.**

12 A. Wholesale sales revenue declined relative to Base NPC due to lower market prices.
13 The average price of actual market sales transactions was \$10.60/megawatt-hour
14 (MWh), or 28 percent, lower than the average price in Base NPC. Lower market

1 prices were partially offset by an increase in wholesale sales volume of market
2 transactions (represented in GRID as short-term firm and system balancing sales).

3 **Q. Please explain the changes in purchased power expense.**

4 A. Purchased power expense decreased due to an \$86 million decrease in long-term
5 purchase power contracts. The expiration of the Hermiston power purchase
6 agreement and the Georgia-Pacific Camas contract resulted in lower purchased power
7 costs of \$85.7 million. Lower long-term purchased power was partially offset by a
8 \$56 million increase in market transactions (represented in GRID as short-term firm
9 and system balancing purchases).

10 Actual market purchases were approximately 2,444 gigawatt-hour (GWh), or
11 77 percent, higher than Base NPC. The increased volume was partially offset by the
12 lower average price of actual market purchase transactions which was \$3.33/MWh, or
13 11 percent, lower than Base NPC.

14 **Q. Please explain the changes in coal fuel expense.**

15 A. Coal fuel expense decreased due to lower coal generation volumes that was partially
16 offset by an increase in the average cost of coal generation. The average cost of coal
17 generation increased from \$23.53/MWh in Base NPC to \$26.45/MWh in the Deferral
18 Period. Coal-fired generation decreased 1,785 GWh, or 17 percent.

19 **Q. Please explain the changes in natural gas fuel expense.**

20 A. The total natural gas fuel expense in Actual NPC decreased by \$37 million compared
21 to Base NPC due to a lower average cost of natural gas generation from \$39.03/MWh
22 in Base NPC to \$17.25/MWh, or 56 percent in the Deferral Period. Reduced costs

1 were partially offset by an increase in natural gas generation volume of 848 GWh, or
2 36 percent, higher than Base NPC during the Deferral Period.

3 **Q. Please provide an overview of the Enbridge natural gas pipeline rupture and its**
4 **impact on company operations and costs.**

5 A. On October 9, 2018, the Enbridge natural gas pipeline that transports natural gas
6 produced in the Western Canadian Sedimentary Basin to consumers in British
7 Columbia (B.C.) and, through interconnecting pipelines, the Northwestern United
8 States (U.S.), experienced a massive rupture. The pipeline was brought back into
9 service in late October 2018; however, at a reduced capacity until testing of the many
10 segments of the pipeline can be completed. Currently the pipeline is operating at
11 approximately 85 percent of capacity. Original estimates expected the pipeline to be
12 back in full service sometime late spring 2019; however, revised forecasts are now
13 calling for full service to be established sometime in September 2019. Spot natural
14 gas prices at the Sumas B.C.-U.S. border trading point have traded as high as
15 \$159 per million British thermal units on days of intense demand.

16 The pipeline rupture and reduced operating capacity has impacted electricity
17 prices primarily at the Mid-Columbia power market hub, but electricity prices are
18 increasing at other trading points where PacifiCorp transacts. Because of
19 PacifiCorp's geographical and resource diversity, the impact to the company was not
20 as severe as other utilities and power producers that have a high reliance on Sumas
21 natural gas supplies. PacifiCorp has one natural gas-fired generator—the Chehalis
22 plant—that is sourced from the Sumas natural gas hub. Due to the pipeline rupture, at
23 times the availability of natural gas flowing to the Sumas gas hub has been limited,

1 which can cause the price to run the Chehalis plant to be uneconomical or at times
2 even unable to run. As a result, overall the natural gas constraint at Sumas has
3 contributed to higher prices at Mid-Columbia, putting upward pressure on net power
4 costs.

5 **Q. What is the current status of natural gas flow at the Sumas natural gas hub?**

6 A. As of the date of this filing, natural gas flows to the Sumas gas hub continue to be
7 restricted as pipeline repair and testing continues. Westcoast Pipeline, which operates
8 the Enbridge pipeline, has indicated that flows to Sumas will be restricted through the
9 summer of 2019. These restrictions will cause increased price volatility and higher
10 power prices this summer at Mid-Columbia.

11 **COLSTRIP PLANT UNIT 4 OUTAGE**

12 **Q. What is the company's role in the management and operation of the Colstrip**
13 **plant?**

14 A. The Colstrip plant is a four unit coal-fired power plant located in Montana. The plant
15 is jointly-owned by various parties, of which the company is a 10 percent owner in
16 Unit 3 and Unit 4. In accordance with Order 08 in Docket UE-061546, only the
17 company's ownership of Unit 4 is included in the company's Washington base rates
18 and computation of Actual NPC. The operator, Talen Montana (Talen), plans and
19 carries out the daily operation of the facility.

20 As stated above, in accordance with the joint-owner agreement, the company
21 has a 10 percent ownership in Colstrip Unit 4. The company participates to the fullest
22 extent of the joint-ownership agreement, including participation in on-going
23 operations and the management committee, in which a representative from the

1 company is present at a monthly meeting to discuss, among other items, safety,
2 operations, environmental, finance, and to provide input for decisions related to the
3 Colstrip plant.

4 **Q. How much of the Colstrip plant is included in the company's Washington rates?**

5 A. In accordance with Order 08 in Docket UE-061546, the company's ownership of
6 Unit 4 is included in the company's Washington base rates and computation of Actual
7 NPC. Colstrip Unit 4 has a generating capacity of 740 megawatts (MW); the
8 application of the company's ownership concludes up to 74 MW of generating
9 capacity that is included in Actual NPC on a WCA basis. For calendar year 2018, the
10 allocation factor used to allocate Colstrip Unit 4 to Washington was 22.6 percent.
11 Therefore, approximately 17 MW of generating capacity was allocated to serve
12 Washington customer load in 2018.

13 **Q. Please summarize the calendar year 2018 environmental compliance outages
14 that occurred at the Colstrip plant.**

15 A. During quarterly compliance assurance stack testing at the end of June 2018, test
16 results for Colstrip Unit 4 indicated the unit was operating in excess of Mercury and
17 Air Toxics Standard (MATS) limits (Colstrip has a site wide average requirement that
18 has to be met with all plants impacting the results). As a result, the unit was removed
19 from service on June 29, 2018. Significant efforts were made by Talen to return
20 Unit 4 to operations in 2018, including thorough inspections, testing, cleaning,
21 modifications, analysis, adjustments, repairing, and replacement of potential
22 contributors. On September 4, 2018, Unit 4 demonstrated compliance with MATS
23 Standard and was subsequently put back online.

1 Talen contracted with Sologic to provide a root case analysis (RCA). The
2 company will supplement this filing with the final RCA once it is available.

3 **Q. How did the company assist Talen during the outage?**

4 A. During the Colstrip Unit 4 outage, the PacifiCorp provided additional support beyond
5 the joint ownership agreement and sent two industry expert engineers employed by
6 the company to assist Talen with troubleshooting. A boiler tuning expert and an
7 environmental chemistry expert were sent to the Colstrip plant to assist in July 2018.
8 Along with this, our management representative helped provide feedback regarding
9 potential approaches and ideas in identifying the issue.

10 **Q. Please describe the estimated replacement power costs associated with the**
11 **Colstrip Unit 4 outage.**

12 A. The estimated replacement power costs associated with the Colstrip Unit 4 outage due
13 to MATS compliance is approximately \$0.5 million. This value is computed by
14 comparing the monthly Mid-Columbia market price to the average cost of generation.
15 Any lost MWh was determined by dispatching the unit when generation costs were
16 less than the market prices. To calculate the estimated replacement power cost, the
17 lost MWh is multiplied by the difference between the market price and the average
18 generation cost. The replacement power costs are then multiplied by 10 percent, the
19 company's ownership share in Colstrip Unit 4 and are then allocated to Washington.

20 **Q. How did the outage affect company operations?**

21 A. Colstrip produces less than three percent of the energy provided by resources
22 included in the WCA. Due to the diverse resource mix and wide array of generation

1 resources PacifiCorp uses to meet its obligations, the company was able to rely on
2 other resources to serve Washington customer load during the Colstrip Unit 4 outage.

3 **IMPACT OF PARTICIPATING IN THE EIM**

4 **Q. Are the actual benefits from participating in the EIM with CAISO included in**
5 **the PCAM deferral?**

6 A. Yes. Participation in the EIM provides benefits to customers in the form of reduced
7 Actual NPC. The EIM benefits are embedded in Actual NPC through lower fuel and
8 purchased power costs. The company is able to calculate the margin realized on its
9 EIM imports and exports, which is the inter-regional benefit. The company's EIM
10 inter-regional benefit for the deferral period was approximately \$57 million, or
11 \$22.7 million on a WCA basis.

12 **Q. How does the company calculate its actual EIM benefits?**

13 A. Using actual information from the EIM, including five- and 15-minute pricing, the
14 company identifies the incremental resource that could have facilitated the transfer to
15 an adjacent EIM area or the CAISO in each five-minute interval. The benefit is then
16 calculated as the difference between the revenue received less the expense of
17 generation assumed to supply the transfer. In the event of an import, the benefit is
18 equal to the cost of the import minus the avoided expense of the generation that
19 would have otherwise been dispatched.

20 **Q. Does this conclude your direct testimony?**

21 A. Yes.