Exhibit No. MGW-1T
Docket UE-_____
Witness: Michael G. Wilding

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

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

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

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

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

Q. Have you testified in previous regulatory proceedings?

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

PURPOSE OF TESTIMONY

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

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

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

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

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

SUMMARY OF THE PCAM DEFERRAL CALCULATION

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

A. The Commission's Order 09 in Docket UE-140762 approved the PCAM to allow the company to track unexpected variations in power costs in the PCAM deferral account. If the cumulative positive or negative balance in the PCAM deferral account, including monthly interest, exceeds $17 million either a surcharge or sur-credit is triggered.

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

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

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

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

2018 PCAM CALCULATION

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

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

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

- o Between $4 and $10 million; shared 50 percent by customers and 50 percent by the company;
- o Greater than $10 million; shared 90 percent by customers and 10 percent by the company;
- o Between -$4 and -$10 million; shared 75 percent by customers and 25 percent by the company; and
- o Less than -$10 million; shared 90 percent by customers and 10 percent by the company.

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

For the Deferral Period, the PCAM differential was approximately a $12.6 million credit. After application of the deadband and asymmetrical sharing band, the company is seeking approval to credit the PCAM balancing account with approximately $6.9 million including interest. A summary of the deferral calculation is shown in Table 1.

Table 1
Summary of PCAM Account Balance

Calendar Year 2018 PCAM Deferral		
Actual PCAM Costs ($/MWh)	$	28.58
Base PCAM Costs ($/MWh)		31.76
PCAM Cost Differential ($/MWh)		(3.18)
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	**$**	**(6,913,591)**

** Calculated monthly*

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

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

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

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$_{\$/MWh}$ -	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

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

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

A. The total-company adjusted Actual NPC in the Deferral Period were approximately $498 million on a WCA basis. This amount captures all components of NPC as defined in the company's general rate case proceedings and modeled by the company's Generation and Regulation Initiative Decision Tool (GRID) model. Booked NPC are adjusted to reflect a balanced WCA consistent with the methodology used in Docket UE-140762. Specifically, it includes amounts booked to the following FERC accounts:

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

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

Account 503 - Steam from other sources;

Account 547 - Fuel, other generation;

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

Account 565 - Transmission of electricity by others.

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

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

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

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

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

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

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

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

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

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

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

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

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

A. Interest is accrued monthly on the PCAM deferral balance at the FERC interest rates 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).

$0.1 million of interest refundable to customers.

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

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

Table 2
Deferred Balancing Account

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

DIFFERENCES IN NPC

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

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

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

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

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

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

Q. Please explain the changes in wholesale sales revenue.

A. Wholesale sales revenue declined relative to Base NPC due to lower market prices. The average price of actual market sales transactions was $10.60/megawatt-hour (MWh), or 28 percent, lower than the average price in Base NPC. Lower market prices were partially offset by an increase in wholesale sales volume of market transactions (represented in GRID as short-term firm and system balancing sales).

Q. Please explain the changes in purchased power expense.

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

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

Q. Please explain the changes in coal fuel expense.

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

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

A. The total natural gas fuel expense in Actual NPC decreased by $37 million compared to Base NPC due to a lower average cost of natural gas generation from $39.03/MWh in Base NPC to $17.25/MWh, or 56 percent in the Deferral Period. Reduced costs were partially offset by an increase in natural gas generation volume of 848 GWh, or 36 percent, higher than Base NPC during the Deferral Period.

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

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

The pipeline rupture and reduced operating capacity has impacted electricity prices primarily at the Mid-Columbia power market hub, but electricity prices are increasing at other trading points where PacifiCorp transacts. Because of PacifiCorp's geographical and resource diversity, the impact to the company was not as severe as other utilities and power producers that have a high reliance on Sumas natural gas supplies. PacifiCorp has one natural gas-fired generator—the Chehalis plant—that is sourced from the Sumas natural gas hub. Due to the pipeline rupture, at times the availability of natural gas flowing to the Sumas gas hub has been limited, which can cause the price to run the Chehalis plant to be uneconomical or at times even unable to run. As a result, overall the natural gas constraint at Sumas has contributed to higher prices at Mid-Columbia, putting upward pressure on net power costs.

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

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

COLSTRIP PLANT UNIT 4 OUTAGE

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

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

As stated above, in accordance with the joint-owner agreement, the company has a 10 percent ownership in Colstrip Unit 4. The company participates to the fullest extent of the joint-ownership agreement, including participation in on-going operations and the management committee, in which a representative from the company is present at a monthly meeting to discuss, among other items, safety, operations, environmental, finance, and to provide input for decisions related to the Colstrip plant.

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

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

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

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

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

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

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

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

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

Q. How did the outage affect company operations?

A. Colstrip produces less than three percent of the energy provided by resources included in the WCA. Due to the diverse resource mix and wide array of generation resources PacifiCorp uses to meet its obligations, the company was able to rely on other resources to serve Washington customer load during the Colstrip Unit 4 outage.

IMPACT OF PARTICIPATING IN THE EIM

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

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

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

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

Q. Does this conclude your direct testimony?

A. Yes.