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, 2016 Power Cost Adjustment Mechanism	Docket UE-_____

PACIFIC POWER & LIGHT COMPANY

DIRECT TESTIMONY OF MICHAEL G. WILDING

June 2017

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with Pacific Power & Light Company (Pacific Power or Company), 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 Manager, Net Power Costs.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Master of Accounting degree 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. Before joining the Company, I was employed as an internal auditor for Intermountain Healthcare and as an auditor for the Utah State Tax Commission. I have been employed by the Company since February 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony on behalf of the Company in regulatory proceedings in California, Oregon, Idaho, Utah, and Wyoming.

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 beginning January 1, 2016, through December 31, 2016 (Deferral Period). More specifically, my testimony provides:

- Background on the PCAM and an accounting of how the PCAM balance was calculated for the Deferral Period;

- A discussion of the main drivers of the differences between adjusted actual west control area net power costs (Actual NPC) and west control area net power costs in rates (Base NPC); and
- A discussion about the Company's participation in the energy imbalance market (EIM) with the California Independent System Operator (CAISO) and the benefits 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 a surcharge or credit of $17 million, there are no proposed changes to Tariff Schedule 97.

SUMMARY OF THE PCAM DEFERRAL CALCULATION

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

A. The Commission's Order 09 in Docket UE-140762 approved the PCAM to allow the Company to recover or refund significant, unexpected variations in power costs if and when the cumulative positive or negative balance in the PCAM deferral account, including monthly interest, exceeds $17 million.

Q. Please summarize the calculation of the PCAM deferral included in this filing.

A. For the 12-month period ending December 2016, the cumulative PCAM differential was an approximate $5.6 million credit before application of the deadband and sharing band. After application of the deadband and asymmetrical sharing band, the filing results in a credit of approximately $1.2 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 2016 PCAM deferral on a monthly basis. Detailed workpapers supporting Exhibit No. MGW-2 are provided separately.[1]

Q. Please describe the other exhibits to your testimony and how they are related to the calculation of the PCAM deferral.

A. Exhibit No. MGW-3 is provided to depict the adverse geologic conditions at the time of the abandonment of the Joy Longwall, which is described in further detail later in my testimony.

2016 PCAM CALCULATION

Q. Please describe the calculation of the PCAM deferral included in this filing.

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:
  - Between $4 and $10 million; shared 50 percent by customers and 50 percent by the Company;

[1] Confidential workpapers are provided to the Commission in accordance with WAC 480-07-160.

- Greater than $10 million; shared 90 percent by customers and 10 percent by the Company;
- Between $-4 and $-10 million; shared 75 percent by customers and 25 percent by the Company; and
- 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 (12-months ending December 2016) the PCAM differential was $5.6 million credit before application of the deadband. After application of the deadband and asymmetrical sharing band, the Company is seeking approval to credit the PCAM balancing account approximately $1.2 million including interest.

A summary of the deferral calculation is shown in Table 1.

Table 1
Summary of PCAM Account Balance

Calendar Year 2016 PCAM Deferral		
Actual PCAM Costs ($/MWh)		$ 30.35
Base PCAM Costs ($/MWh)		$ 31.76
$/MWh PCAM Cost Differential	**$**	**(1.41)**
Washington Sales (MWh)		3,981,654
Total PCAM Differential*	$	(5,605,682)
Total Deferrable ABOVE Deadband	$	-
Total Deferrable BELOW Deadband		(1,605,682)
Washington Deferral after Sharing	$	(1,204,262)
Interest Accrued through December 31, 2016	$	(3,956)
Requested PCAM Recovery	**$**	**(1,208,218)**

** 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:

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

Where:

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

Base $\text{NPC}_{\$/\text{MWh}}$ - 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.

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 Actual NPC for the Deferral Period and how were they determined?

A. Actual NPC in the Deferral Period were approximately $528 million on a west control area 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 west control area 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 remove accounting entries that relate to operations before implementation of the PCAM on April 1, 2015, and to reflect previously approved ratemaking treatment of several items, including:

- Sacramento Municipal Utility District (SMUD) wholesale sales contract revenues;[2]
- Situs assignment of the generation from Oregon solar resources procured to satisfy ORS 757.370 solar capacity standard;
- 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 $120 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 2016.

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

A. The Company has included in the PCAM actual EIM costs that are not otherwise

[2] *Wash. Utils and Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 08 (June 21, 2007).

included in NPC. These EIM costs include the return on rate base, ongoing operations and maintenance expense, and depreciation expense. This treatment was proposed by Boise White Paper and agreed to by the Company in Docket UE-152253 to match recovery of EIM costs and benefits.[3] 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 did the Company collect from Washington customers during the Deferral Period?

A. During the Deferral Period, the Company received approximately $126.5 million in Base PCAM revenue from Washington customers, approximately $5.6 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 $1.2 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 $3,956 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 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

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

account.

Table 2
Deferred Balancing Account

	Washington Customers
Balancing Account Activity	
Prior Deferral	$ -
Current Year PCAM Deferral	(1,204,262)
Interest	(3,956)
Activity Through December 31, 2016	**$ (1,208,218)**
December 31, 2016 Balance	**$ (1,208,218)**

DIFFERENCES IN NPC

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

A. On a west control area basis, Actual NPC for the Deferral Period were $528 million, less than Base NPC for the Deferral Period by approximately $22 million. Table 3 below provides a high level summary of the difference between the Base NPC and Actual NPC by category on a west control area basis.

Table 3
Net Power Cost Reconciliation ($millions)

	TOTAL
Base NPC	**$ 551**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	38
Purchased Power Expense	(30)
Coal Fuel Expense	(9)
Natural Gas Expense	(23)
Wheeling and Other Expense	2
Total Increase/(Decrease)	**$ (22)**
Adjusted Actual NPC 2016	**$ 528**

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. Base rates became effective April 1, 2015.

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

A. Actual NPC were lower than Base NPC due to a $30 million reduction in purchased power expense, $23 million reduction in natural gas fuel expense, and a $9 million reduction in coal fuel expense. These reduced expenses were partially offset by a $38 million decrease in wholesale sales revenues and a $2 million increase in wheeling and other expenses.

Q. Please explain the changes in wholesale sales revenue.

A. The decline in wholesale sales revenue was driven by lower market prices and a reduction in wholesale sales volume of market transactions (represented in the

Company's production dispatch model (GRID) as short-term firm and system balancing sales). The average price of actual market sales transactions was $16.03/MWh, or 43 percent, lower than the average price in Base NPC.

Q. Please explain the changes in purchased power expense.

A. The reduction in purchased power expense was due to a decrease in long-term purchase power contracts partially offset by market transactions (represented in GRID as short-term firm and system balancing purchases). The expiration of the Hermiston power purchase agreement and the Georgia-Pacific Camas contract resulted in lower purchased power costs of $57.1 million.

Actual market purchases increased purchased power expense by $23.4 million compared to Base NPC due to volume of market purchases. Actual market purchases were approximately 2,300 GWh, or 73 percent, higher than Base NPC. The increased volume was partially offset by the lower average price of actual market purchase transactions which was $8.67/MWh, or 28 percent, lower than Base NPC.

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

A. The total natural gas fuel expense decreased by $23 million compared to Base NPC and was driven by lower average generation costs. The average cost of natural gas generation decreased by $12.07/MWh from $39.03/MWh in Base NPC to $26.97/MWh (31 percent).

Q. Please explain the changes in coal fuel expense.

A. Actual coal fuel expense is $8.9 million lower than Base NPC due to a 21 percent reduction in coal generation. The lower generation is partially offset by increased

coal costs at the Jim Bridger plant, which was $24.06/MWh in Base NPC compared to $29.42/MWh in the Deferral Period.

JIM BRIDGER COAL COSTS

Q. Please explain the changes in the coal fuel expense at Jim Bridger compared to the Deferral Period.

A. The total coal fuel expense at the Jim Bridger plant was approximately $7.9 million lower than Base NPC, while generation was 2,111 GWh lower. The average cost of generation at Jim Bridger increased $5.37/MWh, or 22 percent, compared to Base NPC. The driver in the increase at Jim Bridger is the increase in coal costs, which are $42.9 million higher than the coal costs used in Base NPC. Third party coal costs decreased by $0.24 per ton, or $0.1 million, and Bridger Coal Company (BCC) mine costs increased by $13.82 per ton, or $42.9 million.

Q. Please describe the change in BCC coal costs relative to the deferral period.

A. BCC costs increased by approximately $42.9 million due to the following reasons: 1) lower British thermal unit (Btu) content of coal, $3.4 million; 2) spreading costs over the reduced volume of tons produced, $19.4 million; 3) abandonment cost of the Joy Longwall, $12.5 million; and 4) costs of the Joy Longwall recovery efforts, $7.6 million.

Q. Please explain why coal with a lower Btu content increases coal costs.

A. The Btu content of coal is positively correlated to the amount of energy produced from burning the coal; the higher the Btu content, the more energy the coal produces when burned. Because the actual Btu content of BCC coal was lower than the Btu content of BCC coal in Base NPC, it was necessary to burn higher quantities of BCC

coal than would have been burned had the actual Btu content equaled the Btu content in Base NPC.

Q. Please explain how the decreased generation at Jim Bridger impacted BCC's costs.

A. Generation decreased at the Jim Bridger plant by 21 percent compared to Base NPC resulting in less coal being burned. As seen in Table 4 below, BCC deliveries decreased from 4.0 million tons in the base period to 2.8 million tons in 2016, a reduction of 29 percent, and BCC production decreased from 3.5 million tons in the base period to 2.4 million tons in 2016, a reduction of 32 percent. Lower production levels at BCC increase the BCC cost per ton as costs are spread over fewer tons of coal. Notably, if the Btu content of BCC coal would have been higher, less BCC coal would have been needed to produce the actual Jim Bridger generation.

Table 4

Tons - PacifiCorp Portion						
millions	Bridger Plant Deliveries			Bridger Mine Production		
	2016 Actuals	WA Base NPC (4/15 - 3/16)	Variance	2016 Actuals	WA Base NPC (4/15 - 3/16)	Variance
Third Party Sources	1.6	1.5	0.0			
Bridger Coal	2.8	4.0	(1.1)	2.4	3.5	(1.1)
Surface Mine	1.7	1.5	0.2	1.6	1.4	0.2
Underground Mine	1.1	2.5	(1.4)	0.8	2.1	(1.4)
Jim Bridger Plant Total	4.4	5.5	(1.1)			

Q. Please describe the costs associated with the Joy Longwall.

A. During mining operations at the end of December 2015, a section of panels in the Joy Longwall became stuck in soft claystone material due to difficult geological conditions. Significant efforts were made by BCC to return the Joy Longwall to operations in 2016; however, due to unsafe working conditions, the Joy Longwall was ultimately abandoned. Included in the 2016 PCAM is the Company's portion of the

Joy Longwall recovery and abandonment costs. The recovery costs are the expenses incurred in the effort to return the Joy Longwall to operations. The abandonment costs include the net book value (cost of the asset less accumulated depreciation) of the lost asset, longwall related construction work in process, materials and supply, inventory items, and deferred longwall costs.

Q. Is this the longwall that the Company sold to BCC at the time of the Deer Creek mine closure?

A. Yes. In an arm's length transaction, the Company sold the Joy Longwall to BCC in September 2015 for the appraised value.

Q. What were the geological conditions that led to the Joy Longwall becoming stuck?

A. Exhibit No. MGW-3 is a depiction (not to scale) of the mining conditions of the longwall panel, or section of the mine, where the Joy Longwall was stopped by adverse geological conditions. In Exhibit No. MGW-3 the green line is the top of the coal seam and the pink line is the bottom. Underneath the coal seam is a layer of hard sandstone which is the mine floor. This sandstone layer, or mine floor, varies in depth of approximately one to three feet at any given spot in the longwall panel, and underneath the mine floor is soft claystone material. During operation of the Joy Longwall, the coal seam thinned, and undulations, or structural rolls, in the floor became more pronounced and frequent. The Joy Longwall crew attempted to navigate through this area, but the soft claystone material under the mine floor became exposed. This is shown in Exhibit No. MGW-3 as the dashed portion of the pink line.

Q. What actions were taken to climb above the claystone material and place the Joy Longwall back on the mine floor (i.e. hard sandstone layer)?

A. The operators of the Joy Longwall attempted to climb onto the hard sandstone layer by changing the cutting profile of the Joy Longwall. However, the shearer (the part of the longwall that cuts into the coal seam) was unable to operate because it was colliding with other parts of the Joy Longwall. The lack of clearance limited the longwall crew's ability to reestablish a hard, competent floor.

Q. Did other issues complicate Joy Longwall mining efforts?

A. Yes. Other issues included mechanical downtime on the shearer equipment and underground conveying system, extreme weather conditions freezing surface coal transfer facilities, poor quality mine floor, and deteriorating mine roof conditions. Collectively, these issues impeded the Joy Longwall's ability to climb out of the claystone material.

Q. Please describe efforts to advance the Joy Longwall and resume coal production activities.

A. Efforts to climb out of the soft claystone material and reestablish competent roof conditions included pumping foam, tech seal, and grout in the area above the Joy Longwall, installing supports beneath the Joy Longwall, freezing the soft claystone material, and injecting bonding agents into floor and roof.

Q. Were the efforts to stabilize deteriorating section conditions and advance the longwall system successful?

A. No. None of the efforts described above were able to successfully provide the overall floor stability required to advance the Joy Longwall. Ultimately, working conditions

became unsafe and a decision to terminate Joy Longwall recovery efforts was made in early October 2016, with the abandonment costs booked in September 2016.

Q. Why were such efforts made to advance the Joy Longwall and resume production activities?

A. The Joy Longwall was a valuable asset and the Company felt it was prudent to give its best efforts to return the Joy Longwall to production. The mining conditions encountered in the front part of the longwall panel were encouraging, resulting in favorable productivity rates and coal quality, and the longwall panel had approximately 400,000 tons remaining to be mined. Aside from the monetary value, the Joy Longwall provided operational benefits because it has a lower minimum operating height than the DBT Longwall. This operating flexibility enabled the Joy Longwall to extract a higher quality product in areas with thinning coal seams relative to the DBT Longwall.

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. Financially binding EIM operation went live November 1, 2014, and all net benefits arising from EIM operation from January 1, 2016, to December 31, 2016, are included in the PCAM deferral.

Q. Has the Company quantified the benefits realized during 2016 from participating in the EIM?

A. Yes, the Company has calculated the EIM inter-regional benefit, i.e. the margin

realized on EIM imports and exports. The Company's EIM inter-regional benefit for the Deferral Period was approximately $5.6 million on a west control area basis.

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

A. Using actual information from the EIM, including five- and fifteen-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. What are the estimated 2016 EIM benefits as reported by CAISO?

A. CAISO publishes quarterly EIM Benefit Reports (CAISO Benefit Reports) estimating the benefits realized through EIM operation for each entity that participates in the EIM. The CAISO Benefit Reports estimated EIM benefits attributable to PacifiCorp of approximately $45.5 million on a total-Company basis for the deferral period. The benefits estimated for PacifiCorp in the CAISO Benefit Reports include the benefits of EIM operation due to more efficient dispatch (both inter- and intra-regional), reduced renewable energy curtailment, and reduced flexibility reserves.

Q. What is the difference between the EIM benefits estimated by CAISO and the inter-regional EIM benefits calculated by the Company?

A. The EIM benefits are embedded in the Actual NPC through lower fuel and purchased power costs. However, the Company is able to calculate the margin realized on its EIM imports and exports, the inter-regional benefit. In its quarterly EIM Benefit

Report, CAISO estimates all the benefits of participating in the EIM, including intra-regional dispatch savings (optimizing the resources in PacifiCorp's two Balancing Authority Areas), inter-regional dispatch savings (transacting with other EIM participants), reduced renewable energy curtailment, and flexibility reserve savings (reduced reserves due to diversity across the EIM footprint).

The CAISO calculation utilizes a counterfactual scenario that is built to mimic the more manual dispatch process PacifiCorp utilized in actual operations before participation in the EIM. Based on the subjectivity of the counterfactual scenario, the EIM benefits reports by CAISO are presented as an estimate.

Q. Does this conclude your direct testimony?

A. Yes.