PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 1, 2016

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: Advice No. 16-05
Docket UE 307—PacifiCorp's 2017 Transition Adjustment Mechanism

In compliance with ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing the following proposed tariff pages associated with Tariff P.U.C. OR No. 36, which sets forth all rates, tolls, charges, rules, and regulations applicable to electric service in Oregon. The Company requests an effective date of January 1, 2017.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2017 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. This tariff filing is supported by testimony and exhibits from the following witnesses:

- Brian S. Dickman, Director, Net Power Costs
- Dana M. Ralston, Vice President, Coal Generation and Mining
- Judith M. Ridenour, Specialist, Cost of Service and Pricing

B. Tariff Sheets

Nineteenth Revision of Sheet No. INDEX-3	Tariff Index	Table of Contents – Schedules
Seventh Revision of Sheet No. 201-1	Schedule 201	Net Power Costs – Cost-Based Supply Service
Sixth Revision of Sheet No. 201-2	Schedule 201	Net Power Costs – Cost-Based Supply Service
Seventh Revision of Sheet No. 201-3	Schedule 201	Net Power Costs – Cost-Based Supply Service
Fifth Revision of Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Items
Fourth Revision of Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Items
Fifth Revision of Sheet No. 205-3	Schedule 205	TAM Adjustment for Other Items

C. Correspondence

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

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Additionally, PacifiCorp requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
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Please direct informal correspondence and questions regarding this filing to Erin Apperson, Manager, Regulatory Affairs, at (503) 813-6642.

A copy of this filing has been served on all parties to PacifiCorp's 2016 TAM proceeding, docket UE 296. Confidential material in support of the filing has been provided to parties under Order No. 16-128.

Sincerely,

R Bryce Dalley | aura

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: UE 296 Service List
UE 307 Service List

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Direct Testimony and Exhibits in Docket UE 307 on the parties listed below via e-mail and/or overnight delivery in compliance with OAR 860-001-0180.

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Dated this 1st day of April 2016.

Carrie Meyer
Supervisor, Regulatory Operations

Docket No. UE 307
Exhibit PAC/100
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Brian S. Dickman

April 2016

DIRECT TESTIMONY OF BRIAN S. DICKMAN

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs and Load Forecasting.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Before joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing. I have been employed by the Company since 2003, including positions in revenue requirement and regulatory affairs. I assumed my current role managing the Company's net power cost group in March 2012.

Q. Have you testified in previous regulatory proceedings?

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

PURPOSE AND SUMMARY OF TESTIMONY

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

A. I present the Company's proposed 2017 Transition Adjustment Mechanism (TAM) net power costs (NPC). Specifically, my testimony:

- Summarizes the content of the filing;

- Defines NPC and describes the NPC increase in the 2017 TAM compared to the final NPC in the Company's previous TAM, docket UE 296 (2016 TAM);[1]
- Describes changes to the Company's resource portfolio since the 2016 TAM; and
- Explains the modeling of certain NPC items as requested by the Commission in its 2016 TAM final order.[2]

Q. Please identify the other Company witnesses supporting the 2017 TAM.

A. Two additional Company witnesses provide testimony supporting the Company's filing. Mr. Dana M. Ralston, Vice President, Coal Generation and Mining, provides testimony supporting the coal costs included in the 2017 TAM. Ms. Judith M. Ridenour, Regulatory Specialist, Pricing & Cost of Service, presents the Company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

SUMMARY OF PACIFICORP'S 2017 TAM FILING

Q. Please provide background on the Company's 2017 TAM filing.

A. The TAM is the Company's annual filing to update its NPC in rates and to set the transition adjustments for direct access customers. Along with the forecast NPC, the 2017 TAM also includes test period forecasts for: 1) Other Revenues as stipulated in docket UE 216; 2) incremental benefits and costs related to the Company's participation in the energy imbalance market (EIM) with the California Independent System Operator Corporation (CAISO); and 3) renewable energy production tax

[1] *In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, preliminary Order No. 15-353 (Oct. 26, 2015), final Order No. 15-394 (Dec. 11, 2015).
[2] *Id.*

credits (PTCs) as prescribed by Senate Bill (SB) 1547, which was signed into law and became effective March 8, 2016. The Company is filing the 2017 TAM on a stand-alone basis without a general rate case and proposes that new rates become effective on January 1, 2017.

Exhibit PAC/101 shows that the 2017 TAM results in an increase to Oregon rates of approximately $19.9 million (unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis). As explained in Ms. Ridenour's testimony, the 2017 TAM results in an overall average rate increase of approximately 1.6 percent.

Q. What are the estimated NPC in the TAM for calendar year 2017?

A. As shown on Exhibit PAC/101, the forecasted normalized NPC for calendar year 2017 are $379.2 million.[3] This is approximately $7.0 million higher than the NPC of $372.2 million in the 2016 TAM. On a total-company basis, the normalized NPC for calendar year 2017 are $1.567 billion, which is approximately $45.0 million higher than the $1.522 billion reflected in the 2016 TAM. Details of total-company NPC for 2017 are provided in Exhibit PAC/102.

Q. Does the proposed rate increase for the 2017 TAM reflect changes in Oregon load since the 2016 TAM?

A. Yes. The 2017 load forecast used in the Company's calculation of NPC reflects decreased Oregon load compared to the 2016 forecast loads in the 2016 TAM. Due to the decreased Oregon load, the Company anticipates it will collect $6.6 million less for NPC based on the rates approved in the 2016 TAM, increasing the overall rate

[3] PAC/101, Dickman/1, line 37.

change for the 2017 TAM.

Q. Because this is a stand-alone TAM filing, did the Company include an update to Other Revenues for certain items related to NPC, as stipulated in docket UE 216?

A. Yes. Exhibit PAC/103 shows the update to Other Revenues compared to the level set in the 2016 TAM. Other Revenues are expected to decrease in 2017 due mainly to the termination of the Bonneville Power Administration (BPA) South Idaho Exchange in June 2016. Projected Other Revenues are approximately $1.2 million lower in 2017, causing a corresponding increase in the TAM rate change.[4]

Q. Please explain how the benefits and costs associated with participation in the EIM are treated in the 2017 TAM.

A. The Company's initial filing includes both the benefits and costs associated with participation in the EIM. The expected incremental EIM benefits relative to the optimized NPC modeled by the Generation and Regulation Initiative Decision Tools model (GRID) are reflected as a reduction to the NPC forecast. EIM-related costs, including capital and operations and maintenance expense, are added to the TAM to match the benefits. This same treatment was approved in the 2016 TAM, and it is consistent with the stipulation in docket UE 287, which first addressed EIM-related costs in the TAM. Details supporting EIM benefits and costs are included in Exhibit PAC/104 and Exhibit PAC/105, and are discussed later in my testimony.

[4] Consistent with prior TAM filings, the variance in Other Revenues is adjusted for changes in load in the same manner as the adjustment to NPC related components.

Q. Please describe the treatment of renewable energy production tax credits in the 2017 TAM.

A. Under Section 18(b) of SB 1547, the Company is required to provide an annual forecast of its renewable energy production tax credits for inclusion in rates:

> Each public utility that makes sales of electricity shall forecast on an annual basis the projected state and federal production tax credits received by the public utility due to variable renewable electricity production, and the Public Utility Commission shall allow those forecasts to be included in rates through any variable power cost forecasting process established by the commission.

Consistent with this language, as part of the 2017 TAM, variances in projected PTCs are included in this filing. Exhibit PAC/106 shows the forecast level of PTCs for 2017 compared to the level of PTCs established in base rates in docket UE 263, the Company's 2014 general rate case (2014 Rate Case). As reflected in Exhibit PAC/106, the 2014 Rate Case reflected approximately $17.2 million of PTCs. Due to the expiration of PTCs at several Company-owned facilities, the forecast of Oregon-allocated PTCs for the 2017 test period is approximately $13.7 million. When adjusted for load changes, and after the tax gross-up factor is applied, the reduction of PTCs results in an increase in the Oregon revenue requirement of approximately $5.0 million. Pursuant to Section 18(b) of SB 1547 the Company has included this increase in the 2017 TAM.

Q. How will the Company reflect PTCs in future NPC filings?

A. In the annual TAM filings, the Company will project the level of PTCs for the test period, and variances from amounts previously reflected in rates will be included as part of the rate adjustments requested in those filings. In addition, variances in forecast PTCs will be addressed consistent with other NPC-related components as part of the Company's annual Power Cost Adjustment Mechanism (PCAM) filings.

Q. Have Oregon's allocation factors changed since the 2016 TAM?

A. Yes. The decrease in projected Oregon load relative to load in other states served by the Company results in a decrease in Oregon's allocation factors and the corresponding share of total-company NPC allocated to Oregon compared with the 2016 TAM. This reduction in allocation factors is reflected in the Company's requested rate increase.

DETERMINATION OF NPC

Q. Please explain NPC.

A. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

Q. Please explain how the Company calculates NPC.

A. NPC are calculated for a future test period based on projected data using GRID. GRID is a production cost model that simulates the operation of the Company's power system on an hourly basis.

Q. Is the Company's general approach to the calculation of NPC using the GRID model the same in this case as in previous cases?

A. Yes. The Company has used the GRID model to determine NPC in its Oregon filings since 2002. Over time, various improvements to the modeling of specific items in GRID have been implemented to better reflect Company operations and to achieve the most accurate NPC forecast for the test period. In Order No. 15-353 in the 2016 TAM, confirmed in final Order No. 15-394, the Commission imposed a one-year moratorium on changes to the GRID model to "allow parties adequate time to understand, review, and evaluate recent changes to the model."[5] Consequently, the Company has not proposed any GRID modeling changes in the 2017 TAM. Later in my testimony, I provide details supporting several modeling issues implemented in the 2016 TAM in an effort to further explain how they have contributed to a more accurate NPC forecast.

Q. Is the Company using the same version of the GRID model as used in its 2016 TAM?

A. Yes.

Q. What inputs were updated for this filing?

A. All inputs have been updated since the 2016 TAM, including: system load; wholesale sales and purchase contracts for electricity, natural gas and wheeling; market prices for electricity and natural gas; fuel expenses; and the characteristics and availability of the Company's generation facilities.

Q. What is the date of the Official Forward Price Curve (OFPC) the Company used in this filing?

A. To ensure that the 2017 TAM reflects current market conditions, the Company's filing utilizes an OFPC prepared on March 3, 2016. In the past, the Company has used its most recent quarterly OFPC from the last business day of December in its initial TAM filings. Since December 2015, however, both electricity and gas prices for the 2017 TAM test period dropped significantly, impacting the relative economics

[5] Order No. 15-353 at 2 and Order No. 15-394 at 2.

of the Company's gas generation, coal generation, and market opportunities. For this reason, the Company prepared a more recent OFPC for use in its initial filing.

Q. Will the Company continue to update the OFPC through the pendency of this proceeding?

A. Yes. In accordance with the TAM Guidelines, the Company's reply update will be prepared using the most recent OFPC, the November indicative update will be prepared using an OFPC from within nine days of the filing, and the November final update will be prepared using an OFPC from within seven days of the filing.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is the same information contained in Exhibit PAC/102, and an electronic version is included in the workpapers accompanying the Company's filing. Additional data with more detailed analyses are also available in hourly, daily, monthly, and annual formats by heavy load hours (HLH) and light load hours (LLH).

DISCUSSION OF MAJOR COST DRIVERS IN NPC

Q. Please generally describe the changes in NPC compared to the 2016 TAM.

A. Table 1 illustrates the change in total-company NPC by category from the NPC baseline in the 2016 TAM:

Table 1
Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2016	**$1,521**	**$24.94**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	$46	
Purchased Power Expense	$7	
Coal Fuel Expense	$48	
Natural Gas Fuel Expense	($55)	
Wheeling and Other Expense	($2)	
Total Increase/(Decrease) to NPC	**$45**	
OR TAM 2017	**$1,566**	**$25.86**

As shown in Table 1, the increase in NPC is driven mainly by a reduction in wholesale sales revenue and an increase in coal fuel expense, along with a small increase in purchased power expense. The increase is offset by a significant reduction in natural gas fuel expenses and a slight reduction in wheeling expense.

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is driven by lower sales volumes and lower prices for wholesale market sales transactions. Market sales (represented in GRID as short-term firm and system balancing sales) in the 2016 TAM were included at an average price of $24.40 per megawatt-hour (MWh), while market sales in the current case are included at an average price of $23.81/MWh, a two percent decline in price.

While the Company's average sale price decreased only slightly, the number of low-price hours increased significantly. In the 2016 TAM, Mid-Columbia (Mid-C) market prices were less than $16/MWh in 12 percent of the hours in the year, whereas in the 2017 TAM this increased to 20 percent of the hours in the year. Where possible, the Company backs down resources which are more expensive than market during low price periods rather than making sales.

Q. Why did purchased power expense increase?

A. The increase in purchased power expense is mainly attributable to a full year of generation output from power purchase agreements (PPAs) with qualifying facilities (QFs) that are expected to reach commercial operation in 2016. The Company has also included 10 new QF contracts that are expected to reach commercial operation in 2017. As a result, QF purchase expenses are $99.0 million higher than in the 2016 TAM. This increase is offset by the expiration of the Company's long-term purchase agreement for half of the output of the Hermiston power plant which was included for six months in the 2016 TAM, as well as by lower market prices. Market purchases (represented in GRID as short-term firm and system balancing purchases) in the 2016 TAM were included at an average price of $27.23/MWh, while market purchases in the current case are included at an average price of $24.60/MWh, a 10 percent decrease.

Q. Please explain the increase in coal expense in the current proceeding.

A. The increase in coal fuel expense is driven by changes in coal generation volumes since the prior TAM, as well as by higher average costs at the Company's Bridger Coal facility than were reflected in the Company's final update in the 2016 TAM. In the 2016 TAM, low market prices for natural gas caused generation from the Company's gas-fired units to displace generation at coal-fired units. Low market prices projected for 2017 are again resulting in reductions in generation at certain coal-fired units. Additional details regarding the cost of coal during the test year are provided in the direct testimony of Mr. Ralston.

As described by Mr. Ralston, several of the Company's coal-fired plants have supply agreements with minimum take volumes. Reductions in coal consumption at these plants will result in relatively small reductions in coal fuel expense due to take or pay contract clauses or liquidated damages. In the Company's initial filing, the following plants are dispatched to ensure minimum coal take: [redacted]. If market prices decline further as the case proceeds, as occurred in the 2016 TAM, the minimum take requirements at other plants will also need to be accounted for. For example, a seven percent reduction in [redacted] coal consumption from the initial filing would bring it down to the contractual minimum. The TAM updates for coal generation and fuel expense will account for such contractual minimums, as applicable.

Q. Please discuss the change in natural gas fuel expense compared to the 2016 TAM.

A. Natural gas expense is lower than in the 2016 TAM due to decreased generation output at the Company's natural-gas-fired plants. The average cost of natural gas generation was relatively flat, dropping only slightly from $22.71/MWh in the 2016 TAM to $22.61/MWh in the current TAM. The reduction in the market price of electricity means there are fewer hours when the natural gas fired plants are used to support wholesale sales or avoid market purchases. Consequently, projected natural gas generation decreased by 2.3 million MWh, or 15 percent, compared to the 2016 TAM. In addition, the fixed charges and tiered variable charges applicable under

Lake Side 1's contract with Questar Gas during the 2017 TAM are sufficient to meet its minimum annual bill, which contributed to a net reduction in pipeline expense compared to the 2016 TAM.

Q. Please describe the decrease in the wheeling and other expense category.

A. Expenses in this category are lower primarily due to lower Idaho Power Company wheeling rates during the forecast period. Idaho Power Company's transmission tariff demand was reduced as a result of its exchange of transmission assets with PacifiCorp, which closed in November 2015. The reduction in demand will increase Idaho Power Company's tariff rates but will not be fully reflected until October 2017. Integration charges also increased due to higher solar generation in the 2017 TAM. Solar integration charges reflect the levels assumed in the Company's 2015 Integrated Resource Plan (IRP).

CHANGES TO THE COMPANY'S RESOURCE PORTFOLIO

Q. What changes are expected to occur with regard to the Company's resource portfolio relative to the 2016 TAM?

A. The Company's 2017 TAM incorporates a number of resource changes to account for operational differences expected to occur by the end of the test period in this case.

- *Thermal Upgrades/Environmental Controls*—Environmental upgrades at Jim Bridger 3 in November 2015 resulted in an increased minimum operating level. Environmental upgrades will result in a similar impact to Jim Bridger 4 in November 2016.

- *BPA South Idaho Exchange*—Under an exchange agreement with BPA, the Company supplies energy to serve BPA's load in South Idaho and is returned energy in its PACW. This contract terminates on June 30, 2016. The 2016 TAM included this contract for 6 months, and it is eliminated in the 2017 TAM.

- *Hermiston Purchase*—The Company's Hermiston purchase contract for the output of the 50 percent share of the Hermiston plant not owned by the Company terminates on June 30, 2016. Starting July 1, 2016, the NPC forecast includes only the Company's 50 percent ownership share of the two Hermiston units. The Company is currently finalizing the operating arrangements that will take effect July 1, 2016. [redacted]. The Company anticipates a final operating protocol will be in place by the time of its reply filing and will update its filing if needed.

- *Solar QF Purchases*—The Company currently has QF contracts in place with solar generating capacity that will total over 1,000 MW by the end of 2017. At present, just 166 MW of this capacity has reached commercial operation and over 800 MW of capacity is expected to come online in 2016. The Company will continue to monitor the progress of these facilities and update as appropriate in its reply filing.

Q. Does this case include new QF PPAs that are not yet operational but that are expected to achieve commercial operation during the forecast period?

A. Yes. At the time the Company prepared the 2017 TAM, it had signed ten new PPAs with QFs that are expected to reach commercial operation in 2017 and have not previously been included in rates. After the Company's initial 2017 TAM study was prepared, the Company received a termination notice for a 3MW solar project that was previously expected to reach commercial operation in 2016. This change will be reflected in the Company's reply filing. Based on the information known to the Company when this case was prepared, the Company has a commercially reasonable good faith belief that these QFs will reach commercial operation before or during the forecast period.

Q. Did the Company extend any PPAs in its NPC study that are scheduled to expire during the forecast period?

A. Yes. Several existing QF PPAs terminate before the end of the forecast period, and the Company assumed that these customers will execute PPAs to continue selling to the Company at the most recent avoided cost rates. The Company will update the status of these PPAs as new information becomes available.

GRID MODELING SUPPORT

Q. Is the Company proposing any GRID modeling changes in the 2017 TAM?

A. No. Consistent with the TAM Guidelines, the Company has updated the GRID model inputs with the most recent information available at the time of filing, but the Company has not proposed any modeling changes in the 2017 TAM. In the 2016 TAM, the Company proposed various GRID modeling changes to improve the accuracy of forecast NPC, including changes to reflect costs related to day-ahead and real-time balancing transactions, thermal plant forced outage events, natural gas unit start-up costs and energy, hourly regulation reserve requirements, curtailment of certain Company-owned wind facilities, and actual performance of wind PPAs. At the conclusion of the 2016 TAM, the Commission approved the Company's proposals but imposed a one-year moratorium on GRID model changes and directed the Company to work with parties to increase understanding of recent modeling changes, such as short-term transactions and outage modeling.[6]

Q. Has the Company provided support for these issues in the 2017 TAM?

A. Yes. The Company's workpapers include detailed data supporting the modeling of each of the issues approved in the 2016 TAM. In addition, I provide testimony describing the modeling of short-term transactions and thermal plant forced outages. Finally, I explain the updated forecast of EIM benefits and continued collection of

[6] Order No. 15-394, p. 14.

actual data from EIM operations.

Q. Is it necessary that the NPC modeling in GRID continue to be updated in the Company's annual TAM proceedings?

A. Yes. It is imperative to continually update the methods and inputs used with the GRID model to better reflect the operation of the Company's system and to improve the accuracy of the NPC forecast. Modifications are often necessary to capture changed circumstances or regulations, changes in the Company's resources or operations, or an increased understanding of what drives NPC. A more accurate NPC forecast will minimize variances with actual costs and will send appropriate price signals to customers so they can make informed decisions regarding their energy consumption, balancing the interests of the Company and customers.

Day-Ahead and Real-Time System Balancing Transactions

Q. Please describe how system balancing transactions are included in GRID.

A. System balancing transactions are required to balance the hourly load and resources in the GRID model for the TAM test period. The GRID model calculates the least-cost solution to balance the Company's load and resources each hour. The model makes purchases in the wholesale market (labeled as "system balancing purchases" in the NPC report) in the hours for which the Company does not have enough owned or contracted resources to meet its load. The model also makes wholesale market sales (labeled as "system balancing sales" in the NPC report) when it has excess resources for a given hour.

In the 2016 TAM, the Commission approved the Company's proposal to differentiate prices paid for purchases from prices received for sales, based on historical variations from average actual market prices for purchases and sales in a given month. The Commission also approved the Company's proposal to include additional volumes of purchases and sales to account for the additional transactions that are necessary when buying or selling electricity on a forward basis using standard block products and then balancing the system more precisely on an hourly basis in the real-time markets. Both of these modeling refinements are required to more accurately capture the cost of balancing the Company's system in the short-term markets versus a model that is perfectly balanced each hour within fractions of a megawatt hour and with perfect foresight of system conditions.

Q. How do actual operations differ from the GRID model logic?

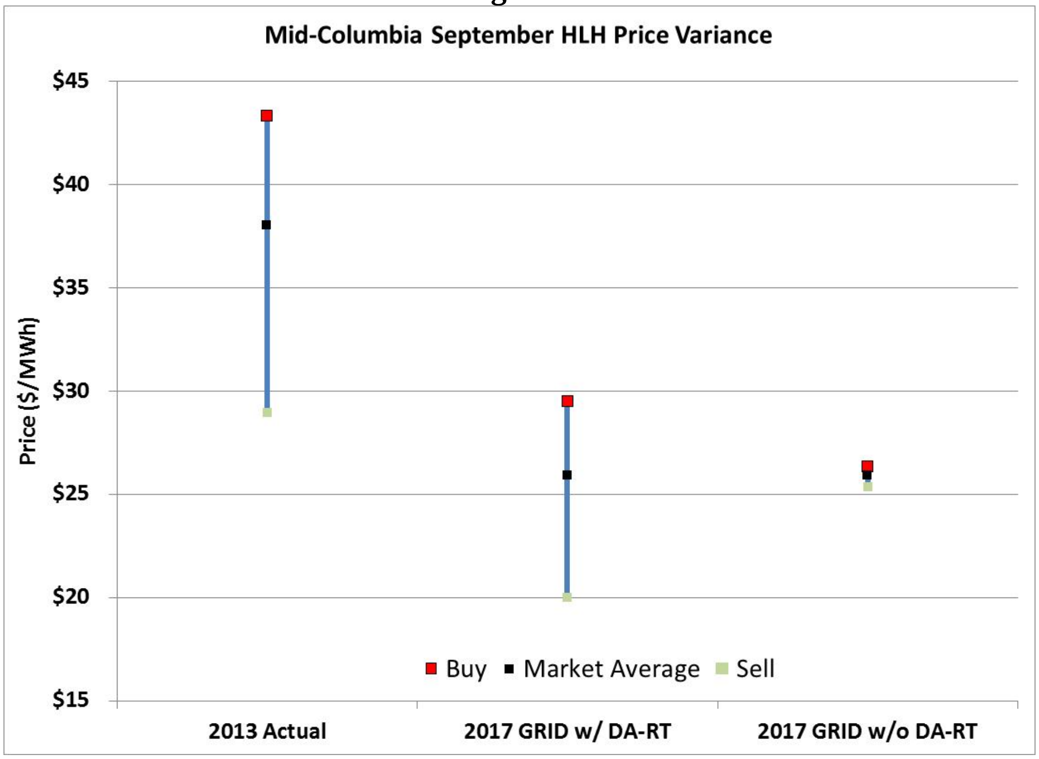
A. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The monthly and daily position is calculated as the average for the respective time horizon during standard block HLH and LLH periods; for example, the average HLH position during the month of January or the average LLH position on a given day in February. The products used to balance the Company's forward position in the wholesale market are available in flat 25 MW blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. In real-time operations, the Company balances its position in the hourly real-time market. At that point, the Company must transact to maintain a balanced system and, as a result, becomes a price-taker subject to whatever price is available at the time.

Q. Please review why the system balancing adjustment is needed to differentiate the market prices for purchases and sales.

A. Before the 2016 TAM, the GRID model used an hourly price curve developed from monthly HLH and LLH forward market prices. Hourly prices were simply the product of applying a scalar, or shape, to the monthly average prices. These scalars are identical within a given month for each weekday of that month. In addition, the prices are input into the model and do not change regardless of the volume of the system balancing transactions or other system conditions in the model. In reality, however, prices vary within each month and the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods. As a result, the average cost of the Company's daily and hourly short-term firm purchases has been consistently higher than the average actual monthly market price, while the average revenue from its daily and hourly short-term firm sales has been consistently lower than the average actual monthly market price.

As shown in Figure 1 below, absent the Company's proposed modeling refinements, the variance between market purchase prices and market sales prices is insignificant compared to historical levels.

Figure 1



Q. Did the Company quantify the impact of this on the Company's past NPC?

A. Yes. In the 48 months ended June 2015, the Company's day-ahead and real-time transactions increased NPC by an average of $7.0 million per year compared to the historical monthly average market prices. Approximately $4.6 million of this impact was a result of higher-than-average purchase prices, while $2.4 million was due to lower-than-average sales prices.

Q. Under the system balancing methodology approved in the 2016 TAM, how did the Company calculate the adjustment to the monthly forward price curve used in GRID?

A. The calculation is based on the Company's short-term firm transactions at a given market hub, with deliveries spanning less than one week.[7] The Company limited the calculation of its adjustment to transactions with a delivery period of less than one week as these are necessary to balance the Company's system and cannot be postponed. To calculate the price adjustment, the Company first calculates the average price of actual real-time and day-ahead transactions from the 48 months ended June 2015. Second, the average realized price is compared to the average market price for that month, and the difference is multiplied by the total historical volume to calculate the net cost versus if the transactions had been done at the average market price. Third, the difference in cost is divided by the average historical volume to calculate the price adder for each month. Fourth, the price adder is used to adjust prices in the GRID model and the model is allowed to simulate system dispatch including system balancing sales and purchases.

Q. Did the Company also calculate a forecast of additional purchase and sale volumes that arise from using monthly, daily, and hourly products to meet the balancing position determined by GRID?

A. Yes. The system balancing sales volume determined by GRID would need to be increased by 2.5 million MWh, or roughly 30 percent, to account for the use of monthly, daily, and hourly products. System balancing purchase volume would be increased by an equal and offsetting amount as the net position determined by GRID is unchanged.

[7] Transactions that have deliveries spanning more than one week are excluded because they will contain a price hedging component because both market price and the Company's demand are increasingly uncertain over longer time frames.

Q. Did the Company include these additional volumes in the 2017 TAM forecast?

A. Yes. The Company added to its NPC forecast the incremental balancing volumes associated with using standard products to cover the open position determined by GRID. These volumes are priced so the overall cost of the Company's day-ahead and real-time balancing transactions relative to the forecasted monthly market prices is equal to the historical average.

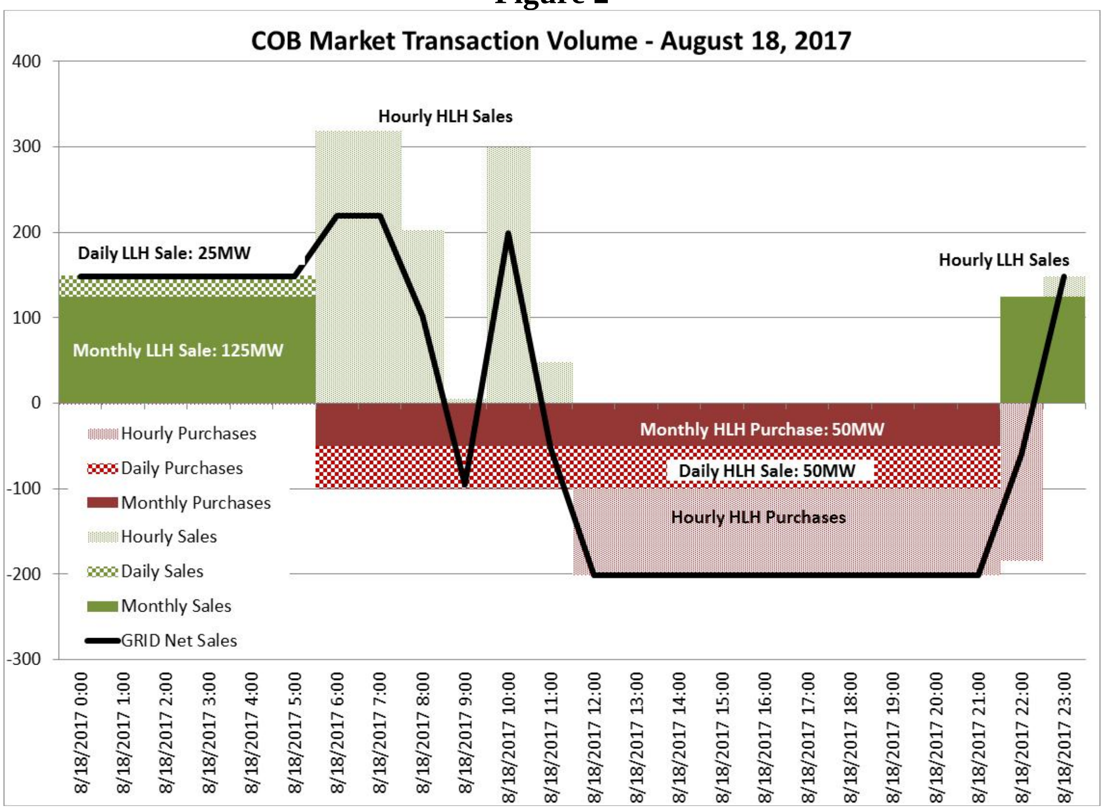
Q. How do the system balancing volumes in GRID compare to the Company's actual volumes?

A. The volume of system balancing transactions generated by GRID is smaller than the volume of similar transactions in actual results. Because GRID balances the Company's load and resources to fractions of a megawatt for each hour in a single step, it avoids the additional purchase and sale transactions that occur in actual operations as the Company progresses through balancing its system on a monthly, daily, and real-time system basis.

For instance, when the Company buys a monthly product that aligns with the Company's average open position for the month, one can expect that roughly half of the days will still have a remaining position to be covered by additional daily purchases. On the other days, the Company will have to make daily sales to unwind the excess volume. The same is true for daily transactions—in some hours the volume acquired will be too low, while in others it will be too high, and additional purchases and sales will be required to cover the Company's actual position.

In addition, buying or selling standard block products for monthly and daily average requirements will not result in a perfect balance of load and resources. This difference then must be closed out in the real-time market where the Company is a price-taker. Figure 2 below illustrates this effect for transactions at the COB market hub during a sample day in the NPC forecast. The solid line represents the hourly sales and purchases generated by the GRID model, and the shaded areas represent monthly and daily standard block products.

Figure 2



Q. What is the impact to NPC when GRID is adjusted to reflect the historical impact of day-ahead and real-time balancing transactions?

A. When the adjustments to reflect the impact of historical day-ahead and real-time transactions are included in GRID, the 2017 TAM NPC increases by approximately $9.1 million.

Thermal Plant Forced Outages

Q. Please summarize the modeling of thermal plant forced outages.

A. Before the 2016 TAM, the Company modeled forced outages at thermal units using a percentage de-rate or "haircut" to nameplate capacity in all hours. In GRID, this approach constrained unit output between minimum operating level and a de-rated maximum, with a slice of each unit being unavailable for dispatch in every hour. Beginning with the 2016 TAM, the Company has modeled forced outages and unit de-rates as discrete events, rather than applying a uniform de-rate to the plant operating characteristics across all hours. During intervals without outage events, units are 100 percent available, and can be used over their full operating range. In addition, because outages are no longer modeled as de-rates, previous adjustments to heat rates and minimum operating levels are no longer required.

Q. Please provide background on modeling thermal plant forced outages.

A. The Commission evaluated the calculation of the appropriate forced outage rate and the modeling of outages in docket UM 1355. In Order No. 10-414, the Commission concluded that the forecasted forced outage rate should be based on a four-year average of actual events, adjusted to remove the impact of extraordinarily lengthy events.[8] The Commission also directed that corresponding "haircuts" should be made to the minimum generation levels and heat rates of thermal generating units to align these unit characteristics with the expected impact of forced outages. The Commission noted that there are different methods of representing forced outages in

[8] *In the Matter of Public Utility Commission of Oregon Investigation into Forecasting Forced Outage Rates for Electric Generating Units*, Order No. 10-414 (Oct. 22, 2010).

production cost models, however, and encouraged the Company and other parties to explore these alternatives in the future. Specifically, the Commission stated:

> When modeling forced outages using the capacity deration approach, utilities are directed to derate a unit's capacity over its entire range of operation…We note that ICNU points out that the current deration approach to modeling forced outages is outdated and that there are more sophisticated methods of representing forced outages in production cost models. We encourage the utilities, ICNU, CUB, and Staff to explore these modeling alternatives in future rate cases involving net variable power costs.[9]

When addressing the heat rate adjustment, the Commission stated:

> Given the current deration approach to modeling forced outages, a corresponding adjustment to the unit's modeled heat rate curve is necessary. However, again we emphasize the lack of sophistication and realism associated with the deration approach.[10]

Q. How are thermal plant outages modeled in the Company's current filing?

A. To reflect the impact of outages on the Company's operations in the forecast period, forced outages are reflected as an hourly schedule of outages. This modeling reflects the range of system operating conditions faced by the Company in actual operations. During intervals without outage events, units are 100 percent available, and can be used over their full operating range. Because outages are no longer modeled as de-rates, adjustments to heat rates and minimum operating levels are no longer necessary. This approach was approved by the Commission in the 2016 TAM.

Q. Does the Company's modeling affect the resulting heat rates in this filing?

A. Yes. This adjustment increases the heat rate of the coal fleet slightly relative to the method adopted in UM 1355, indicating that the prior method overstated the heat rate

[9] Order No. 10-414 at 7.
[10] Order No. 10-414 at 8.

impact associated with the forced outage "haircut." When outages are modeled as discrete events, units appropriately receive the benefits of improved heat rates only when they are dispatched near their maximum capacity.

Q. How did the Company determine the timing and duration of outage events in the 2017 TAM?

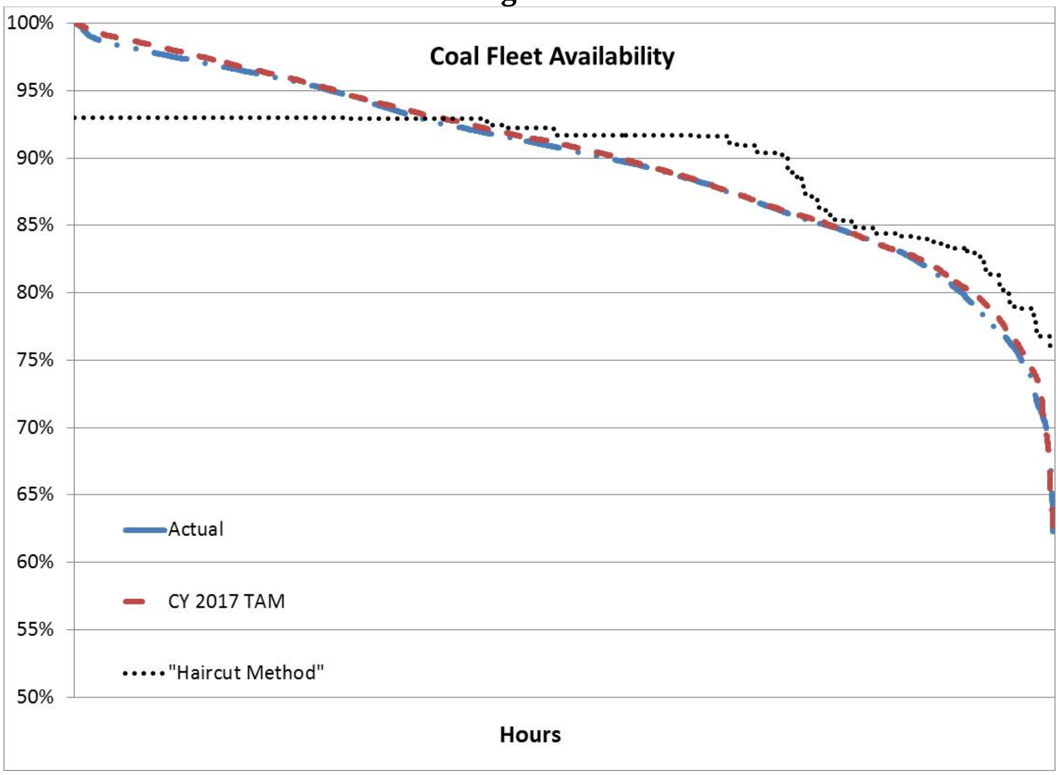
A. Consistent with the Commission's order in docket UM 1355 and the method approved in the 2016 TAM, the Company continued to use a four-year average of actual outage events to determine outages during the test year. Lengthy individual outages were capped at 28 days, and the 48-month average was adjusted using the "collar" adopted in Order No. 10-414.

Because the timing and duration of forced outages are not predictable, the 48-month history of actual events was used to develop a schedule during the forecast test year. Forecasted outage and de-rate events were created by compressing the 48-month history of outage events for each unit into an annual period (i.e., the relative timing and duration of each event in the four-year history was divided by four and placed in the forecast test year in the same sequence the events occurred).

Q. How does the distribution of plant availability across the forecast period compare against the historical distribution?

A. As shown in Figure 3 below, the distribution of coal plant availability (including the impact of forced and planned outages) in the forecast period is quite similar to the historical distribution and much better aligned with actual plant operations than under the prior method.

Figure 3



EIM Costs and Benefits

Q. Please summarize the EIM costs and benefits included in this case.

A. The Company adjusted the 2017 NPC forecast from GRID to reflect incremental EIM benefits from inter-regional dispatch (i.e., exports and imports between EIM participants) and reduced flexibility reserves. The 2017 TAM includes approximately $13.9 million of EIM benefits on a total-company basis as a reduction to the NPC forecast. The Company also included $6.4 million of total-company costs related to EIM participation during 2017. Table 2 below summarizes the EIM-related benefits and costs included in the 2017 TAM and shows changes compared to the 2016 TAM.

Table 2
Total-Company EIM-Related Benefits and Costs

$ millions	**2016 TAM**	**2017 TAM**
Inter-regional dispatch	$8.4	$11.3
Flexibility Reserves	$1.7	$2.6
Test-period EIM benefits	**$10.1**	**$13.9**
Test-period EIM costs	**$5.1**	**$6.4**

Q. Please describe the EIM and the Company's participation in the EIM.

A. The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and between the PacifiCorp and the CAISO balancing authority areas (BAAs). EIM operation went live October 1, 2014, with financially binding operations effective November 1, 2014. By participating in the EIM, the Company's participating generation units are optimally dispatched using the CAISO's computerized security constrained economic dispatch model. The EIM's automated, expanded footprint, co-optimized dispatch replaced the Company's largely isolated and manual dispatch within its two BAAs. Participation in the EIM produces benefits to customers in the form of reduced NPC, partially offset by costs for initial start-up and ongoing operation.

Q. How does participation in the EIM reduce the Company's actual NPC?

A. Participation in the EIM reduces the Company's actual NPC in three ways: (1) optimizing the automated dispatch of participating units in PacifiCorp's BAAs, subject to transmission constraints, using the CAISO's system model; (2) facilitating transactions between CAISO, PacifiCorp, and other EIM participants on a five- and 15-minute basis; and (3) reducing the amount of flexible generating capacity required to be held in reserve by PacifiCorp due to the collective reduction of reserves for the larger and more diversified EIM footprint. Benefits realized for the last two categories are highly dependent on the amount of transfer capacity between EIM participants that is made available for the EIM.

Q. Does each of these benefits cause a corresponding reduction to the GRID model NPC forecast?

A. No. The GRID model NPC forecast already reflects the optimized (i.e., lowest cost) dispatch of PacifiCorp's generating units within its two BAAs, so there are no additional benefits from EIM optimized dispatch (i.e., intra-regional and within-hour dispatch benefits). The other two NPC benefits—inter-regional transactions and reduced flexibility reserves—do produce NPC savings relative to the optimized GRID NPC forecast.

Q. Please describe the EIM-related costs included in the 2017 TAM.

A. Consistent with the structure of the settlement reached in the 2015 TAM and the approved 2016 TAM, the Company included $6.4 million of total-company EIM-related costs in the 2017 TAM. These costs consist of the return on net rate base from the capital investment required to participate in the EIM, depreciation expense, and ongoing operations and maintenance (O&M) expenses and transaction fees.

A summary of the various cost components is provided as Exhibit PAC/105.

Including all EIM-related costs in the 2017 TAM is necessary to ensure that customer rates reflect a proper matching of EIM benefits. This same treatment was approved in the 2016 TAM, and it is consistent with the stipulation in docket UE 287, which first addressed EIM-related costs in the TAM. Rates set in the Company's most recent general rate case, docket UE 263, do not include any EIM-related costs. Until these costs are included in base rates, EIM benefits included in the Company's TAM filings should be net of the ongoing cost of participation.

Q. How is the EIM inter-regional dispatch benefit for transfers to and from CAISO calculated for the forecast period?

A. The export benefits reflect the difference between the Company's revenues from exports to CAISO and the incremental cost of the Company's generation resources that supported the transfer. The export benefit is then expressed in dollars per megawatt-hour of available EIM transfer capability. As in the 2016 TAM, this rate is applied to the available EIM transfer capability in the forecast period. Similarly, the import benefits reflect the difference between the incremental cost of the Company's generation resources that would otherwise have been dispatched, and the costs of imports from CAISO. As in the 2016 TAM, the average import benefit is expressed in dollars per month, and applied to each of the months in the forecast period. Also as in the 2016 TAM, distinct export and import benefits are calculated for two seasons: for the summer period of June through September and for the remaining months of October through May.

Q. Has the EIM inter-regional dispatch benefit for transfers to and from CAISO been updated since the 2016 TAM?

A. Yes. First, the Company's forecast in the 2017 TAM is now based on actual results from January 2015 through December 2015. Second, the Company has now identified the specific incremental resources in each interval of the historical period. In the 2016 TAM, a blend of the incremental costs of the Chehalis, Hermiston, and Jim Bridger was used to approximate the marginal impact of exports and imports.

Q. How does the Company identify the specific incremental resources in each interval of the historical period?

A. Each of the Company's EIM-participating resources submits bids that reflect their cost over their dispatchable range. A unit may have one bid for the entire dispatchable range, or several bids if its heat rate or other operational characteristics create cost variations over that range. The bids are ranked from lowest to highest, and the volume associated with each bid is identified. The resulting supply stack identifies all of the volumes available, and the associated price for each. Starting with the lowest cost unit, EIM dispatches resources up until the total output matches demand for that interval.

When the Company is exporting, the first unit with a bid price that is lower than the transfer price is identified from the supply stack. This represents the last unit the Company dispatched to serve the transfer. The calculation moves down the supply stack until the entire export volume is covered, identifying the prices and volumes of the specific resources the Company would not have dispatched but for the export volume. Similarly, when the Company is importing, the first unit with a bid price that is higher than the transfer price is identified from the supply stack. This represents the next unit the Company would have dispatched to serve its own load, but for the import. The calculation moves up the supply stack until the entire import volume is covered. This identifies the prices and volumes of the specific resources the Company was able to avoid dispatching as they were more expensive than the import cost.

Q. What is the effect of the update to the EIM inter-regional dispatch benefits?

A. Compared to the margins used in the 2016 TAM, the updated EIM inter-regional dispatch margins produce an additional $4.1 million in benefits on a total-company basis.

Q. Has the Company incorporated inter-regional EIM benefits associated with the participation of NV Energy (NVE), Puget Sound Energy (PSE), and Arizona Public Service (APS)?

A. Yes. The methodology for determining these benefits is the same as that utilized in the 2016 TAM. While NVE started participating in EIM in December 2015, at this time the Company has not proposed a change in the associated benefits methodology or incorporated benefits based on the very limited available historical data. PSE and APS are expected to participate in EIM starting in October 2016, so twelve months of benefits from their participation are also included in the 2017 TAM. The Company intends to gather several more months of actual results from NVE's participation which it will incorporate in its reply filing.

Q. Have any other parties expressed interest in joining the EIM in the future?

A. Yes. On November 20, 2015, Portland General Electric (PGE) announced it intends to begin participating in the EIM in October 2017. Initial reports indicate that PGE's participation in the EIM is expected to produce annual inter-regional benefits to existing participants of $2.7 million.[11] The 2017 TAM includes the Company's share of those benefits to existing participants from PGE joining the EIM, based on the same ratio used to account for the participation of APS and PSE in the 2016 TAM.

[11] http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf.

Q. Does the Company's forecast include flexibility reserve benefits from its participation in the EIM?

A. Yes. The regulating reserve requirement modeled in GRID has been reduced by roughly 68 MW to account for the Company's share of the reserve benefit based on the diversified footprint of the EIM. The methodologies for determining the reduction in reserves associated with CAISO, NVE, APS and PSE participation in the EIM are unchanged from the 2016 TAM. The Company has also included the diversity benefit associated with PGE's participation in the EIM beginning in October 2017, using a comparable methodology to that used for APS and PSE in the 2016 TAM. The overall reduction in the Company's reserve requirement from its participation in EIM decreases NPC by approximately $2.6 million on a total-company basis.

COMPLIANCE WITH TAM GUIDELINES

Q. Did the Company prepare this filing in accordance with the TAM Guidelines adopted by Order No. 09-274, as clarified and amended in later orders?

A. Yes. The Company has complied with the TAM Guidelines applicable to the initial filing in a stand-alone TAM.

Q. Did the Company make changes to GRID in this case?

A. No.

Q. Does this filing include updates to all NPC components identified in Attachment A to the TAM Guidelines?

A. Yes.

Q. Did the Company provide information regarding its anticipated TAM updates?

A. Yes. Exhibit PAC/107 contains a list of known contracts and other items that could be included in the Company's TAM updates in this case based on the best information available at the time the Company prepared the NPC study.

Q. What workpapers did the Company provide with this filing?

A. In compliance with Attachment B to the TAM Guidelines, the Company provided access to the GRID model and workpapers concurrently with this initial filing. Specifically, the Company is providing the NPC report workbook and the GRID project report.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 307
Exhibit PAC/101
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Oregon-Allocated Net Power Costs

April 2016

PacifiCorp
CY 2017 TAM

Line no		ACCT.	Total Company: UE-296 Final TAM CY 2016	Total Company: TAM CY 2017	Factor	Factors CY 2016	Factors CY 2017	Oregon Allocated: UE-296 Final TAM CY 2016	Oregon Allocated: TAM CY 2017
1	**Sales for Resale**								
2	Existing Firm PPL	447	14,551,883	12,491,680	SG	25.464%	25.230%	3,705,447	3,151,693
3	Existing Firm UPL	447	-	-	SG	25.464%	25.230%	-	-
4	Post-Merger Firm	447	308,215,401	264,081,138	SG	25.464%	25.230%	78,483,023	66,628,559
5	Non-Firm	447	-	-	SE	24.074%	23.757%	-	-
6	**Total Sales for Resale**		322,767,283	276,572,818				82,188,470	69,780,252
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	5,460,531	5,396,826	SG	25.464%	25.230%	1,390,453	1,361,637
10	Existing Firm Demand UPL	555	25,957,591	23,373,572	SG	25.464%	25.230%	6,609,761	5,897,231
11	Existing Firm Energy	555	33,163,822	31,518,350	SE	24.074%	23.757%	7,983,987	7,487,882
12	Post-merger Firm	555	539,019,217	550,503,265	SG	25.464%	25.230%	137,254,198	138,893,825
13	Secondary Purchases	555	-	-	SE	24.074%	23.757%	-	-
14	Other Generation Expense	555	6,783,968	7,635,782	SG	25.464%	25.230%	1,727,449	1,926,534
15	**Total Purchased Power**		610,385,128	618,427,794				154,965,848	155,567,108
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	21,008,517	20,923,037	SG	25.464%	25.230%	5,349,544	5,278,953
19	Existing Firm UPL	565	-	-	SG	25.464%	25.230%	-	-
20	Post-merger Firm	565	119,121,361	117,404,391	SG	25.464%	25.230%	30,332,698	29,621,523
21	Non-Firm	565	8,447,062	7,680,770	SE	24.074%	23.757%	2,033,579	1,824,737
22	**Total Wheeling Expense**		148,576,940	146,008,198				37,715,820	36,725,212
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	684,036,958	717,322,134	SE	24.074%	23.757%	164,677,719	170,415,756
26	Fuel Consumed - Coal (Cholla)	501	39,725,288	54,710,604	SE	24.074%	23.757%	9,563,620	12,997,715
27	Fuel Consumed - Gas	501	3,867,174	2,221,172	SE	24.074%	23.757%	930,998	527,689
28	Natural Gas Consumed	547	349,178,912	296,984,718	SE	24.074%	23.757%	84,062,690	70,555,295
29	Simple Cycle Comb. Turbines	547	3,229,791	2,464,889	SE	24.074%	23.757%	777,552	585,589
30	Steam from Other Sources	503	4,836,760	4,465,238	SE	24.074%	23.757%	1,164,420	1,060,816
31	**Total Fuel Expense**		1,084,874,883	1,078,168,755				261,177,000	256,142,860
32									
33	**Net Power Cost (Per GRID)**		1,521,069,669	1,566,031,929				371,670,199	378,654,929
34									
35									
36	Oregon Situs Solar Projects		515,121	536,598	OR	100.000%	100.000%	515,121	536,598
37	**Total NPC Net of Adjustments**		1,521,584,790	1,566,568,527				372,185,320	379,191,527
38									
39	Non-NPC EIM Costs*		4,621,885	5,166,061	SG	25.464%	25.230%	1,176,903	1,303,414
40	**Total TAM Net of Adjustments**		1,526,206,675	1,571,734,588				373,362,223	380,494,941
41									
42								Increase Absent Load Change	7,132,718
43									
44						Oregon-allocated NPC Baseline in Rates from UE-296		$373,362,223	
45						$ Change due to load variance from UE-296 forecast		(6,633,884)	
46						2017 Recovery of NPC in Rates		$366,728,339	
47	*EIM Benefits for the 2017 TAM are reflected in net power costs								
48								**Increase Including Load Change**	**13,766,602**
49									
50								Add Other Revenue Change	1,168,275
51								Add PTC Revenue Requirement	4,975,106
52									
53								**Total TAM Increase**	**19,909,983**

Docket No. UE 307
Exhibit PAC/102
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Net Power Costs Report

April 2016

PacifiCorp

_ORTAM17 NPC Study_2016 03 18 CONF

Net Power Cost Analysis

12 months ended December 2017	01/17-12/17	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	12,491,680	1,251,676	986,830	980,003	665,094	688,677	696,019	1,080,215	1,240,829	1,189,077	1,243,738	1,231,067	1,238,455
BPA Wind	2,687,120	342,225	256,241	277,493	207,909	227,367	146,535	124,412	109,081	158,228	208,299	285,920	343,411
Hurricane Sale	7,020	878	877	878	878	878	878	878	878	-	-	-	-
Leaning Juniper Revenue	73,793	4,570	4,839	7,574	4,442	4,843	4,933	8,255	8,869	7,461	6,734	5,462	5,811
UMPA II s45631	3,510,247	593,283	561,909	553,484	438,585	544,744	818,243	-	-	-	-	-	-
Total Long Term Firm Sales	18,769,860	2,192,631	1,810,696	1,819,432	1,316,907	1,466,508	1,666,608	1,213,759	1,359,656	1,354,766	1,458,771	1,522,449	1,587,677
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	1,620,320	533,000	511,680	575,640	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	1,620,320	533,000	511,680	575,640	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	23,350,267	3,449,873	2,802,683	2,982,127	555,722	102,358	359,339	568,820	2,326,911	3,114,681	2,547,673	2,312,494	2,227,588
Four Corners	58,798,638	4,909,764	3,959,369	5,172,199	2,054,060	2,883,923	1,543,925	4,732,201	8,447,541	7,361,960	6,686,529	5,358,647	5,688,519
Mead	25,987,727	2,724,518	938,488	1,704,386	1,511,186	1,503,529	1,729,324	2,170,389	2,564,939	2,845,047	2,480,715	2,717,980	3,097,224
Mid Columbia	20,655,556	1,879,304	241,452	2,202,335	1,750,626	1,479,552	611,118	2,015,155	2,180,117	2,653,619	2,715,810	1,453,094	1,473,374
Mona	20,243,734	1,995,105	1,330,667	774,709	1,434,848	2,020,623	1,213,827	1,343,293	1,493,313	3,103,617	1,557,927	2,255,899	1,719,907
NOB	2,189,364	-	87,231	10,501	166,298	175,694	400,077	802,503	147,896	10,246	-	44,419	344,498
Palo Verde	94,735,895	9,159,959	8,049,836	8,189,554	5,986,884	5,147,600	6,693,275	8,760,404	7,394,874	7,821,196	9,463,893	9,299,351	8,769,068
EIM Exports	10,176,930	557,646	463,566	439,240	802,741	1,024,739	1,543,571	1,641,418	1,169,753	717,096	545,335	548,644	723,179
Trapped Energy	44,528	5,501	439	-	-	3,474	72	-	-	-	4,481	184	30,379
Total System Balancing Sales	256,182,638	24,681,670	17,873,732	21,475,052	14,262,366	14,341,491	14,094,528	22,034,182	25,725,343	27,627,463	26,002,363	23,990,712	24,073,736
Total Special Sales For Resale	276,572,818	27,407,301	20,196,108	23,870,123	15,579,273	15,807,999	15,761,136	23,247,941	27,084,999	28,982,229	27,461,135	25,513,160	25,661,413

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	421,070	24,840	-	16,560	-	-	37,260	191,337	142,794	-	8,280	-	-
Combine Hills Wind	4,755,800	336,025	407,156	494,419	492,219	421,026	360,909	392,436	346,530	293,313	355,247	438,875	417,645
Deseret Purchase	35,850,823	3,125,456	2,997,764	2,414,298	3,082,892	2,561,494	3,082,892	3,125,456	3,125,456	3,082,892	3,125,456	3,001,311	3,125,456
Douglas PUD Settlement	2,264,730	92,679	45,212	143,990	274,540	285,203	318,732	343,468	276,981	116,260	126,385	112,330	128,948
Eagle Mountain - UAMPS/UMPA	2,829,034	206,120	172,597	167,442	256,297	334,339	450,285	340,166	322,110	180,005	119,359	111,987	168,325
Gemstate	1,327,500	105,600	102,300	104,500	102,300	102,300	102,300	102,300	114,900	102,300	125,000	158,100	105,600
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Purchase	83,044	10,380	10,381	10,380	10,380	10,380	10,380	10,380	10,380	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	6,804,970	569,420	553,380	573,430	573,430	573,430	565,410	561,400	561,400	557,390	573,430	573,430	569,420
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
P4 Production	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Rock River Wind	4,834,277	629,232	488,673	514,014	423,855	276,752	254,668	166,493	196,761	267,332	519,266	553,293	543,938
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,962,425	2,805,703	1,816,660	2,149,531	1,624,023	1,436,385	1,208,070	854,752	1,020,918	1,113,901	1,817,062	2,437,015	2,678,408
Top of the World Wind	41,902,933	5,548,005	3,686,827	4,334,908	3,333,919	2,970,104	2,449,666	1,956,114	2,012,140	2,226,881	3,695,185	4,771,487	4,917,700
Tri-State Purchase	9,414,682	764,984	700,136	711,876	694,900	701,564	707,275	1,079,506	951,118	836,692	755,187	725,837	785,608
Wolverine Creek Wind	9,929,128	723,195	845,002	1,076,905	990,530	749,254	802,224	739,900	621,233	654,338	890,756	1,030,723	805,068
Long Term Firm Purchases Total	168,679,287	17,216,526	14,101,015	14,987,138	14,134,173	12,697,180	12,624,989	12,138,649	11,977,639	11,706,172	14,385,487	16,189,313	16,521,006
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	7,101,728	655,496	733,271	822,755	1,039,444	1,055,106	815,226	388,011	293,607	271,727	273,460	303,435	450,189
QF Idaho	7,705,331	627,479	582,096	647,255	675,219	789,478	852,007	785,526	674,001	633,023	493,560	484,808	460,880
QF Oregon	49,617,599	3,036,503	3,104,657	3,720,963	4,802,354	5,384,326	5,381,939	5,190,156	4,905,734	4,341,981	3,689,386	2,906,567	3,153,032
QF Utah	9,748,057	668,527	694,721	823,860	865,820	948,616	968,971	901,230	891,975	837,083	798,688	707,366	641,200
QF Washington	289,953	-	-	-	11,400	26,395	46,567	62,073	66,363	54,308	22,846	-	-
QF Wyoming	200,930	20,883	20,160	23,124	15,756	14,190	11,322	13,844	14,321	12,840	13,067	20,342	21,081
Biomass One QF	14,869,664	1,399,748	1,300,383	1,395,037	1,129,345	888,319	866,565	880,091	1,518,511	1,593,094	1,323,760	1,268,565	1,306,248
DCFP QF	149,052	9,090	8,344	11,431	11,081	16,211	17,512	15,443	12,696	10,534	18,981	12,038	5,692
Enterprise Solar I QF	11,776,513	575,402	624,569	896,870	1,025,481	1,281,175	1,358,744	1,548,412	1,388,445	1,164,791	836,595	591,160	484,870
Escalante Solar I QF	11,131,922	525,988	582,855	852,108	986,414	1,183,991	1,273,621	1,448,734	1,338,703	1,095,782	816,063	561,318	466,346
Escalante Solar II QF	10,639,749	503,123	557,403	814,322	942,804	1,131,363	1,217,462	1,384,137	1,278,973	1,047,120	779,924	536,946	446,174
Escalante Solar III QF	10,198,285	488,922	543,066	788,212	914,280	1,097,593	1,178,609	1,333,907	1,235,361	1,011,006	707,954	490,968	408,408
Evergreen BioPower QF	3,038,493	241,956	205,414	230,542	208,662	208,149	237,682	320,484	295,792	295,002	311,253	227,742	255,815
Five Pine Wind QF	7,621,534	522,326	714,520	677,297	661,672	475,334	472,945	586,275	604,204	620,651	690,306	806,955	789,050
Foote Creek III Wind QF	1,616,034	181,968	164,042	219,609	135,665	81,441	75,844	74,500	94,887	103,417	162,332	179,721	142,607
Granite Mountain East Solar QF	11,339,695	567,379	636,527	927,418	1,024,731	1,208,968	1,317,924	1,396,127	1,325,686	1,015,719	838,279	599,442	481,495
Granite Mountain West Solar QF	7,510,615	375,710	421,478	615,336	680,035	801,178	872,514	925,878	877,076	671,880	554,748	396,459	318,323
Iron Springs Solar QF	11,647,333	655,801	685,468	929,313	1,053,774	1,181,555	1,345,860	1,407,586	1,386,454	1,045,621	845,312	596,248	514,342
Kennecott Refinery QF	172,749	-	-	25,335	17,811	29,101	26,524	21,490	18,492	9,167	-	9,716	15,113
Kennecott Smelter QF	917,239	39,425	72,153	81,673	42,287	78,539	112,915	174,850	134,478	85,849	-	45,888	49,183
Latigo Wind Park QF	9,670,784	1,007,477	917,570	1,126,955	893,263	860,620	745,979	668,253	572,323	616,686	799,252	709,690	752,715
Mountain Wind 1 QF	9,355,354	1,464,332	1,095,022	918,677	715,713	509,895	525,547	398,455	469,761	412,814	780,902	955,656	1,108,581
Mountain Wind 2 QF	14,379,185	2,110,066	1,620,157	1,398,474	1,102,046	788,661	936,708	727,753	762,313	690,068	1,150,635	1,473,964	1,618,341
North Point Wind QF	16,733,095	1,104,918	1,536,422	1,492,136	1,473,588	1,045,561	1,061,127	1,318,716	1,389,273	1,399,663	1,545,725	1,705,440	1,660,527
Oregon Wind Farm QF	12,154,347	728,223	945,568	1,113,158	1,292,005	1,254,451	1,221,012	1,200,933	1,076,661	846,318	742,352	871,289	862,376
Pavant II Solar QF	3,324,534	137,284	171,222	278,384	323,737	354,706	341,329	423,049	415,201	325,714	263,613	160,801	129,497
Pioneer Wind Park I QF	10,641,406	1,305,428	926,029	1,189,660	901,601	709,426	649,524	650,952	683,005	451,955	820,623	1,259,004	1,094,200
Power County North Wind QF	4,800,686	366,034	483,048	463,144	452,207	314,979	310,432	331,248	307,411	330,458	458,196	454,287	529,240
Power County South Wind QF	4,371,173	328,366	431,748	424,900	426,383	276,795	280,912	289,475	290,447	300,576	402,367	436,258	482,947
Spanish Fork Wind 2 QF	2,701,900	207,568	166,728	196,191	154,639	148,333	207,958	301,062	334,188	272,207	240,410	243,600	229,017
Sunnyside QF	28,848,919	2,555,426	2,368,831	2,532,855	1,719,797	2,545,965	2,465,683	2,541,820	2,470,800	2,502,313	2,127,627	2,460,222	2,557,580
Tesoro QF	668,007	27,587	66,106	97,535	69,078	71,838	52,062	43,590	45,691	40,160	40,605	49,469	64,285
Three Peaks Solar QF	8,719,753	422,444	485,885	642,764	857,051	892,860	944,180	1,080,614	1,049,186	822,132	690,742	453,714	378,182
Utah Pavant Solar QF	4,047,713	151,429	195,080	330,092	358,347	401,177	452,058	542,053	519,133	412,016	318,907	205,863	161,560
Utah Red Hills Solar QF	11,814,347	495,290	632,485	806,680	1,052,941	1,235,075	1,271,771	1,556,476	1,509,740	1,352,537	828,567	600,728	472,057
Qualifying Facilities Total	321,199,110	23,699,813	23,842,289	27,676,224	28,141,924	29,382,435	30,004,288	31,034,122	30,385,618	26,813,726	24,523,001	22,991,288	22,704,381
Mid-Columbia Contracts													
Douglas - Wells	3,716,274	307,444	307,444	307,444	307,444	307,444	307,444	307,444	307,444	314,181	314,181	314,181	314,181
Grant Reasonable	(1,327)	(111)	(111)	(111)	(111)	(111)	(111)	(111)	(111)	(111)	(111)	(111)	(111)
Grant Surplus	2,030,780	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232	169,232
Mid-Columbia Contracts Total	5,745,727	476,565	476,565	476,565	476,565	476,565	476,565	476,565	476,565	483,302	483,302	483,302	483,302
Total Long Term Firm Purchases	495,624,125	41,392,905	38,419,870	43,139,928	42,752,663	42,556,180	43,105,842	43,649,336	42,839,822	39,003,200	39,391,790	39,663,902	39,708,689

Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	1,565,600	515,000	494,400	556,200	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	1,565,600	515,000	494,400	556,200	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	16,985,493	577,460	1,326,606	2,087,376	2,105,192	1,272,623	2,254,121	1,824,216	2,440,724	1,340,981	382,436	556,615	817,144
Four Corners	13,931,879	825,826	1,071,089	974,623	1,875,120	1,009,281	670,668	1,453,249	2,139,720	985,721	924,436	920,469	1,081,677
Mead	6,196,403	503,398	515,565	730,076	222,009	515,253	410,414	883,340	844,330	275,961	296,526	584,332	415,199
Mid Columbia	45,080,818	3,686,680	699,279	1,574,063	5,375,137	10,493,338	3,299,586	7,806,531	4,287,391	1,628,787	2,646,563	1,333,360	2,250,104
Mona	10,201,912	139,177	965,017	2,794,035	637,615	1,118,151	680,960	412,868	443,935	434,365	276,058	1,292,324	1,007,408
NOB	4,373,681	-	214,590	18,965	226,088	301,330	1,151,947	1,468,111	340,792	16,144	-	102,822	532,891
Palo Verde	12,537,854	836,181	308,116	525,632	940,582	1,218,080	1,669,638	1,498,831	1,861,501	932,064	744,221	276,217	1,726,792
EIM Imports	(1,167,191)	(109,214)	(109,214)	(109,214)	(109,214)	(109,214)	(73,371)	(73,371)	(73,371)	(73,371)	(109,214)	(109,214)	(109,214)
Emergency Purchases	61,438	669	-	799	-	-	-	39,354	9,313	-	11,303	-	-
Total System Balancing Purchases	108,202,287	6,460,176	4,991,048	8,596,355	11,272,530	15,818,842	10,063,964	15,313,131	12,294,334	5,540,653	5,172,328	4,956,926	7,722,001
Total Purchased Power & Net Inter	610,792,012	48,818,081	44,355,318	52,742,483	54,475,192	58,825,022	53,619,805	59,412,467	55,584,156	44,993,852	45,014,118	45,070,828	47,880,689

Wheeling & U. of F. Expense													
Firm Wheeling	144,725,431	11,589,157	11,804,735	12,081,433	11,432,539	11,156,996	12,072,622	12,669,050	11,329,816	11,544,214	12,980,460	13,603,710	12,460,697
C&T EIM Admin fee	1,269,231	105,637	105,558	105,639	105,888	106,009	106,028	105,769	105,769	105,769	105,769	105,669	105,726
ST Firm & Non-Firm	13,536	3,197	2,513	512	82	123	157	135	1,071	24	-	2,002	3,721
Total Wheeling & U. of F. Expense	146,008,198	11,697,991	11,912,807	12,187,584	11,538,508	11,263,128	12,178,807	12,774,955	11,436,656	11,650,007	13,086,229	13,711,381	12,570,145
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	54,710,604	5,193,277	4,750,341	4,940,633	2,902,296	2,893,070	3,797,919	5,304,833	4,954,236	4,854,286	5,010,329	5,254,729	4,854,656
Colstrip	16,711,809	1,510,424	1,429,037	1,183,798	1,112,279	1,482,780	1,530,059	891,014	1,542,482	1,503,273	1,559,280	1,446,684	1,520,698
Craig	27,745,074	2,498,179	2,101,855	2,472,107	1,867,642	2,380,360	2,344,362	1,909,337	2,468,143	2,428,594	2,457,749	2,270,229	2,546,517
Dave Johnston	60,340,107	4,743,382	4,718,097	4,017,641	4,683,174	5,398,873	5,394,303	5,387,702	5,693,911	5,427,012	5,235,718	4,776,072	4,864,222
Hayden	11,276,993	1,022,158	955,077	1,056,084	784,629	841,255	896,183	1,221,003	1,277,962	797,062	473,158	879,074	1,073,350
Hunter	140,976,989	12,570,070	11,342,181	9,839,477	8,473,547	10,514,145	10,890,387	12,662,030	12,789,997	11,934,359	12,894,829	12,832,318	14,233,649
Huntington	111,977,284	10,867,634	8,348,805	10,562,414	6,642,339	7,846,402	7,962,052	9,979,253	10,923,885	9,199,837	7,929,593	9,658,308	12,056,763
Jim Bridger	216,114,550	19,693,736	17,882,443	17,318,361	10,523,006	11,242,529	14,815,788	20,548,981	22,314,425	19,544,737	19,016,621	21,195,962	22,017,959
Naughton	102,964,162	9,392,425	7,901,345	9,240,778	6,711,333	7,112,895	8,760,460	9,335,181	8,849,614	8,889,368	8,770,041	9,035,896	8,964,826
Wyodak	29,215,165	1,973,969	2,042,924	2,624,672	2,471,399	2,623,349	2,519,731	2,709,829	2,366,211	2,547,890	2,552,712	2,245,874	2,536,605
Total Coal Fuel Burn Expense	772,032,737	69,465,253	61,472,106	63,255,965	46,171,643	52,335,658	58,911,243	69,949,163	73,180,866	67,126,418	65,900,029	69,595,147	74,669,245
Gas Fuel Burn Expense													
Chehalis	45,534,799	5,363,092	3,608,334	2,510,943	4,902,151	2,738,071	2,593,985	5,640,514	3,954,462	4,831,617	5,346,137	1,187,776	2,857,717
Currant Creek	32,099,184	2,468,883	1,876,389	1,388,687	1,425,547	1,069,938	2,735,456	5,029,835	5,055,104	4,422,757	2,416,765	1,367,317	2,842,507
Gadsby	1,683,824	-	-	-	-	-	-	832,224	851,600	-	-	-	-
Gadsby CT	1,197,390	41,916	27,994	28	-	-	42,081	417,353	423,180	80,464	97,081	14,690	52,603
Hermiston	28,644,616	2,859,045	2,748,898	2,084,475	1,327,960	95,225	1,777,734	2,825,332	2,972,903	2,935,505	2,538,936	3,063,025	3,415,579
Lake Side 1	60,747,394	6,647,464	3,957,796	5,370,519	4,280,563	5,185,858	3,385,433	5,806,616	6,515,557	5,514,054	3,032,416	5,374,465	5,676,653
Lake Side 2	68,781,786	6,435,239	5,513,715	5,680,535	4,641,230	4,656,919	5,138,854	6,527,666	6,685,150	6,349,682	6,146,041	5,305,978	5,700,777
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	238,688,993	23,815,640	17,733,125	17,035,188	16,577,450	13,746,012	15,673,542	27,079,539	26,457,954	24,134,079	19,577,377	16,313,251	20,545,836
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	26,739,350	2,767,138	2,535,750	2,949,418	2,330,925	2,373,283	2,230,875	2,191,390	2,169,535	2,122,200	2,032,283	1,656,900	1,379,655
Clay Basin Gas Storage	218,948	(38,637)	(38,000)	(6,747)	52,242	52,242	52,242	52,242	52,242	52,242	52,242	(13,611)	(49,753)
Pipeline Reservation Fees	36,023,488	3,022,754	2,883,869	3,020,684	2,974,608	3,020,684	2,976,989	3,059,980	3,060,416	2,979,011	3,025,940	2,975,377	3,023,176
Total Gas Fuel Burn Expense	301,670,779	29,566,894	23,114,745	22,998,542	21,935,225	19,192,221	20,933,649	32,383,151	31,740,148	29,287,533	24,687,841	20,931,916	24,898,914
Other Generation													
Blundell	4,465,238	419,096	384,432	417,678	374,181	392,868	350,009	368,043	385,231	347,779	257,889	386,076	381,957
Integration Charge	7,635,782	666,844	589,336	714,272	671,526	673,196	661,063	616,284	592,943	561,917	618,748	637,172	632,480
Total Other Generation	12,101,020	1,085,940	973,769	1,131,950	1,045,707	1,066,064	1,011,072	984,327	978,173	909,696	876,637	1,023,249	1,014,437
Net Power Cost	**1,566,031,929**	133,226,858	121,632,635	128,446,402	119,587,004	126,874,093	130,893,440	152,256,122	145,835,001	124,985,277	122,103,720	124,819,361	135,372,017
Net Power Cost/Net System Load	**25.86**	**24.77**	**25.59**	**26.02**	**25.99**	**26.16**	**26.45**	**26.64**	**26.32**	**25.83**	**25.80**	**25.61**	**25.12**

Docket No. UE 307
Exhibit PAC/103
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Update to Other Revenues

April 2016

PacifiCorp
CY 2017 TAM
Other Revenues - Stand Alone TAM Adjustment

Line no		Total Company UE-296 Final	Total Company CY 2017	Factor	Factors CY 2016	Factors CY 2017	Oregon Allocated UE-296 Final	Oregon Allocated CY 2017
1	Seattle City Light - Stateline Wind Farm	(9,811,103)	(9,749,394)	SG	25.464%	25.230%	(2,498,269)	(2,459,805)
2	Non-company owned Foote Creek	(904,184)	(900,686)	SG	25.464%	25.230%	(230,239)	(227,246)
3	BPA South Idaho Exchange	(4,691,490)	-	SG	25.464%	25.230%	(1,194,627)	-
4	Little Mountain Steam Revenues	-	-	SG	25.464%	25.230%	-	-
5	James River Royalty Offset		-	SG	25.464%	25.230%	-	-
6								
7	Total Other Revenue	(15,406,778)	(10,650,079)				(3,923,135)	(2,687,051)
8								
9				Decrease (Increase) in Other Revenues Absent Load Change				1,236,084
10								
11				Baseline Other Revenues in Rates			(3,923,135)	
12				$ Change due to load variance from UE 296 CY 2016 forecast			67,809	
13				Other Revenues in Rates using 2017 load forecast			(3,855,326)	
14								
15				**Decrease (Increase) in Other Revenues Including Load Change**				**1,168,275**

Docket No. UE 307
Exhibit PAC/104
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Energy Imbalance Market Import and Export Summary

April 2016

PacifiCorp
Oregon - CY 2017 TAM
EIM Benefits - PacifiCorp - CAISO Imports and Exports

PacifiCorp - CAISO EIM Import and Export Results

	1/1/2015	2/1/2015	3/1/2015	4/1/2015	5/1/2015	6/1/2015	7/1/2015	8/1/2015	9/1/2015	10/1/2015	11/1/2015	12/1/2015	Total	Initial Filing OR TAM CY2017
Export Volume (MWh)	154,281	88,453	93,966	82,893	155,040	195,319	211,647	151,866	87,383	54,672	113,165	134,890	1,523,575	1,045,386
Export Volume (aMW)	207	132	126	115	208	271	284	204	121	73	157	181	174	119
Import Volume (MWh)	20,044	24,757	22,154	19,243	19,505	11,888	9,756	13,859	11,660	20,315	26,508	24,351	224,040	224,040
Import Volume (aMW)	27	37	30	27	26	17	13	19	16	27	37	33	26	26
Transmission Left Open (MWh)	219,389	196,934	192,460	131,104	241,202	265,478	221,797	203,244	197,537	246,422	149,751	148,733	2,414,052	1,632,781
Transmission Left Open (aMW)	295	293	259	182	324	369	298	273	274	331	208	200	276	186
Export Margin	1,222,510	753,588	603,865	537,696	997,371	1,630,360	1,762,451	1,352,010	495,414	444,147	728,625	789,566	$11,317,602	$7,841,879
Import Margin	44,431	250,959	163,906	150,883	114,615	43,919	54,949	93,655	100,960	(30,292)	104,300	74,906	$1,167,191	$1,167,191
Export Load Factor	70%	45%	49%	63%	64%	74%	95%	75%	44%	22%	76%	91%	63%	64%
Export Margin $/MWh	$7.92	$8.52	$6.43	$6.49	$6.43	$8.35	$8.33	$8.90	$5.67	$8.12	$6.44	$5.85	$7.43	$7.50
Export $/MWh Avail Transmission	$5.57	$3.83	$3.14	$4.10	$4.14	$6.14	$7.95	$6.65	$2.51	$1.80	$4.87	$5.31	$4.69	$4.80
Import $/MWh	$2.22	$10.14	$7.40	$7.84	$5.88	$3.69	$5.63	$6.76	$8.66	-$1.49	$3.93	$3.08	$5.21	$5.21
Total Benefit	**$1,266,941**	**$1,004,547**	**$767,771**	**$688,579**	**$1,111,986**	**$1,674,279**	**$1,817,400**	**$1,445,665**	**$596,374**	**$413,855**	**$832,925**	**$864,472**	**$12,484,794**	**$9,009,070**

Docket No. UE 307
Exhibit PAC/105
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Energy Imbalance Market Costs

April 2016

PacifiCorp
Oregon 2017 TAM
EIM Costs

$ dollars

	CY 2017 EIM Costs 13 Month Average					
	Total Company		Factor	Factors CY 2017	Oregon Allocated	
	2016 Final	Initial Filing			2016 Final	Initial Filing
Capital Investment	16,291,370	16,291,370	SG	25.230%	4,148,384	4,110,367
ADIT	(3,009,988)	(2,917,080)	SG	25.230%	(766,454)	(735,989)
Depreciation Reserve	(3,812,898)	(5,152,814)	SG	25.230%	(970,905)	(1,300,072)
Net Rate Base	9,468,484	8,221,476			2,411,026	2,074,306
	10.75%	10.75%			10.75%	10.75%
Pre-Tax Return on Rate Base	$ 1,018,231	$ 884,129	SG	25.230%	$ 259,279	$ 223,069
Operation & Maintenance (Ongoing)	1,264,222	1,942,499	SG	25.230%	321,918	490,099
Depreciation	2,339,433	2,339,433	SG	25.230%	595,706	590,247
Total Revenue Requirement	$ 4,621,885	$ 5,166,061			$ 1,176,903	$ 1,303,414
CAISO Fee in net power costs	$ 491,461	$ 1,269,231	SG	25.230%	125,144	320,231
Total EIM Costs	$ 5,113,347	$ 6,435,292			$ 1,302,047	$ 1,623,646

Docket No. UE 307
Exhibit PAC/106
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Update to Renewable Energy Production Tax Credits

April 2016

PacifiCorp
CY 2017 TAM
Production Tax Credits - Stand Alone TAM Adjustment

			Total Company					**Oregon Allocated**			
Line no	Plant Name	PTC Expiration Date	UE 263 Final*	CY 2017	Factor	UE 263 Factors	Factors CY 2017	UE 263 Final*	CY 2017	Variance	Revenue Requirement
1	JC Boyle	11/7/2015	(103,599)	-	SG	26.053%	25.230%	(26,991)	-	26,991	43,442
2	Blundell Bottoming Cycle	12/1/2017	(1,896,326)	(1,642,252)	SG	26.053%	25.230%	(494,050)	(414,346)	79,704	128,285
3	Glenrock	12/30/2018	(7,646,838)	(7,453,247)	SG	26.053%	25.230%	(1,992,231)	(1,880,479)	111,752	179,865
4	Glenrock III	1/16/2019	(2,861,406)	(2,785,143)	SG	26.053%	25.230%	(745,482)	(702,701)	42,781	68,857
5	Goodnoe	12/17/2017	(6,138,401)	(5,991,082)	SG	26.053%	25.230%	(1,599,238)	(1,511,570)	87,668	141,102
6	High Plains Wind	10/14/2019	(7,115,510)	(7,115,510)	SG	26.053%	25.230%	(1,853,804)	(1,795,267)	58,537	94,216
7	Leaning Juniper 1	9/13/2016	(7,025,884)	-	SG	26.053%	25.230%	(1,830,454)	-	1,830,454	2,946,131
8	Marengo	8/2/2017	(9,042,126)	(5,447,249)	SG	26.053%	25.230%	(2,355,745)	(1,374,359)	981,386	1,579,549
9	Marengo II	6/25/2018	(4,306,194)	(4,306,194)	SG	26.053%	25.230%	(1,121,893)	(1,086,467)	35,426	57,018
10	McFadden Ridge	10/31/2019	(1,979,446)	(1,979,446)	SG	26.053%	25.230%	(515,705)	(499,421)	16,284	26,210
11	Seven Mile	12/30/2018	(8,040,700)	(7,996,481)	SG	26.053%	25.230%	(2,094,844)	(2,017,539)	77,305	124,423
12	Seven Mile II	12/30/2018	(1,583,828)	(1,575,118)	SG	26.053%	25.230%	(412,635)	(397,408)	15,227	24,508
13	Dunlap I Wind	9/29/2020	(8,132,932)	(8,132,932)	SG	26.053%	25.230%	(2,118,873)	(2,051,966)	66,907	107,687
14											
15	Total Production Tax Credit		(65,873,190)	(54,424,654)				(17,161,943)	(13,731,523)	3,430,420	5,521,291
16											
17	Increase (Decrease) in Revenue Requirement (Gross-Up for Taxes) of Production Tax Credits Absent Load Change										5,521,291
18											
19	Baseline Production Tax Credits in Rates									(17,161,943)	
20	$ Change due to load variance from UE 263 CY 2014 forecast									339,348	
21	Production Tax Credits in Rates using 2017 load forecast									(16,822,595)	
22											
23	Increase (Decrease) in Revenue Requirement (Gross-Up for Taxes) of Change due to Load Variance									(546,184)	
24											
25	**Increase (Decrease) in Revenue Requirement of Production Tax Credits Including Load Change**										**4,975,106**

*From Docket No. UE 263, Exhibit PAC/1002, Page 2.20

PacifiCorp
CY 2017 TAM
Calculation of Production Tax Credits - Stand Alone TAM Adjustment

		Total Company					
		Generation (KWh)		Tax Rate		Tax Credit	
Line no		UE 263 Final	CY 2017	UE 263 Final	CY 2017	UE 263 Final	CY 2017
1	JC Boyle	9,008,583	-	$ 0.012	$ 0.012	$ 103,599	$ -
2	Blundell Bottoming Cycle	82,448,946	71,399,101	$ 0.023	$ 0.023	$ 1,896,326	$ 1,642,179
3	Glenrock	332,471,221	324,054,206	$ 0.023	$ 0.023	$ 7,646,838	$ 7,453,247
4	Glenrock III	124,408,962	121,093,166	$ 0.023	$ 0.023	$ 2,861,406	$ 2,785,143
5	Goodnoe	266,887,001	260,481,820	$ 0.023	$ 0.023	$ 6,138,401	$ 5,991,082
6	High Plains Wind	309,369,981	309,369,981	$ 0.023	$ 0.023	$ 7,115,510	$ 7,115,510
7	Leaning Juniper 1	305,473,220	-	$ 0.023	$ 0.023	$ 7,025,884	$ -
8	Marengo	393,135,919	236,836,928	$ 0.023	$ 0.023	$ 9,042,126	$ 5,447,249
9	Marengo II	187,225,822	187,225,822	$ 0.023	$ 0.023	$ 4,306,194	$ 4,306,194
10	McFadden Ridge	86,062,880	86,062,867	$ 0.023	$ 0.023	$ 1,979,446	$ 1,979,446
11	Seven Mile	349,595,650	347,673,073	$ 0.023	$ 0.023	$ 8,040,700	$ 7,996,481
12	Seven Mile II	68,862,073	68,483,383	$ 0.023	$ 0.023	$ 1,583,828	$ 1,575,118
13	Dunlap I Wind	353,605,729	353,605,731	$ 0.023	$ 0.023	$ 8,132,932	$ 8,132,932
14	Total Production Tax Credit					$ 65,873,189	$ 54,424,580

Docket No. UE 307
Exhibit PAC/107
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

List of Expected or Known Contract Updates

April 2016

List of Known Items Expected to be Updated During the 2017 Oregon TAM

Sales and Purchases of Electricity and Natural Gas

1. New electricity sales and purchase contracts, physical and financial, including contracts with qualifying facilities.
2. Changes in contract terms of existing electricity sales and purchase and exchange contracts.
3. New natural gas sales and purchase contracts, physical and financial.
4. Changes in contract terms of existing natural gas sales and purchase contracts.
5. Contracts whose prices are linked to market indexes and inflation rates.
6. Sales contract with Black Hills Company for energy price and fixed payments.
7. Purchase contracts for generation and fixed costs from the Mid Columbia projects.
8. Purchase contract with Tri-State Generation and Transmission Association Inc. for energy price.
9. The Company's qualifying facility contract with NorWest Energy 5, LLC (Arlington) has been terminated by the developer and will be removed.
10. Purchase expenses of PGE Cove based on PGE projection.
11. Election decision for Grant Meaningful Priority.

Transportation and Storage of Natural Gas

12. New pipeline and storage contracts for transporting natural gas from market to Company's generating facilities.
13. Changes in contract terms of existing pipeline and storage contracts.
14. Contracts whose prices are linked to market indexes and inflation rates.

Wheeling Expenses and Transmission

15. New transmission contracts to wheel power to serve the Company's load obligations.
16. Changes in contract terms of existing transmission contracts.
17. Wheeling expenses that are impacted by changes in third-parties' transmission tariff rates.
18. Contracts whose prices are linked to market indexes and inflation rates.

19. BPA has filed a complaint with FERC in docket EL15-13 regarding transmission service for its South Idaho loads. The Company's transmission rights related to Colstrip are under dispute and could be impacted.

Other

20. Energy Imbalance Market benefit estimates, including import and export margins and volumes, as well as flexibility reserve diversity credits.

Coal Expense Update Items

The table below lists the coal and transportation contracts that maybe affected by changes in volumes as well as changes to market indexes and inflation rates.

		Captive		Fixed Price Coal Contracts		Escalating Coal Contracts		Transportation Contracts	
Plant	Supplier/Mine	Volume	Price	Volume	Price	Volume	Price	Volume	Price
Bridger	Bridger Coal Company/Bridger	√							
	Lighthouse Resources/Black Butte								
	Union Pacific Railroad							√	√
Cholla	Peabody/Lee Ranch					√	√		
	BNSF Railway							√	√
Colstrip	Westmoreland/Rosebud					√	√	√	√
Craig	Trapper Mining Inc/Trapper	√							
	Western Fuels/Colowyo						√		
	Union Pacific Railroad								√
Hayden	Peabody/Twentymile					√	√		
	Union Pacific Railroad							√	√
Hunter	Bowie/Sufco, Dugout, Skyline			√	√				
Huntington	Bowie/Sufco, Dugout, Skyline			√	√				
	Rhino Energy/Castle Valley			√	√				
	Utah Trucking							√	√
D Johnston	Open Position					√	√		
	Cloud Peak/Cordero								
	BNSF Railway							√	√
Naughton	Westmoreland/Kemmerer					√	√		
Wyodak	Black Hills/Wyodak					√	√		

Docket No. UE 307
Exhibit PAC/200
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Dana M. Ralston

April 2016

DIRECT TESTIMONY OF DANA M. RALSTON

TABLE OF CONTENTS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Dana M. Ralston. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Vice President of Coal Generation and Mining.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I have been the Vice President of Coal Generation and Mining for the Company since January 2010. For 34 years prior to that, I held a number of positions of increasing responsibility within Berkshire Hathaway Energy's generation organization, including the plant manager position at the Neal Energy Center, a 1,600 megawatt generating complex. In my current role, I am responsible for operation and maintenance of PacifiCorp's coal-fired generation fleet, coal fuel supply, and mining.

Q. Have you testified in previous regulatory proceedings?

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

PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. I explain the Company's overall approach to providing coal supply for the Company's coal-fired generating plants, and support the level of coal costs included in fuel expense in the Company's 2017 Transition Adjustment Mechanism (TAM). To demonstrate the reasonableness of these costs, my testimony will:

- Explain the primary causes behind the changes to the total-company coal fuel expense reflected in the 2017 TAM;
- Provide background on third-party coal contracts and current contract price re-openers; and
- Review the Company's affiliate mine coal prices.

OVERVIEW OF THE COMPANY'S COAL SUPPLIES

Q. How does the Company plan to meet fuel supplies for its coal plants in 2017?

A. As reflected below in Confidential Table 1, the Company employs a diversified coal supply strategy. The Company will supply approximately 85.1 percent of its 2017 coal requirements with third-party coal supplies and 14.9 percent with coal from the Company's affiliate mines. More specifically: (1) approximately 47.8 percent of the Company's total coal requirement will be supplied under fixed-price contracts; (2) approximately 30.8 percent will be supplied under contracts that escalate or de-escalate based on changes to producer and consumer price indices; and (3) approximately 6.5 percent of the total coal requirement will be supplied to the Dave Johnston plant from currently unidentified Powder River Basin (PRB) mines.

Confidential Table 1: Coal Source Deliveries

[redacted]

Q. Has total coal fuel expense in the 2017 TAM increased from the level reflected in the Company's 2016 TAM?

A. Yes. As stated in the testimony of Mr. Brian S. Dickman, coal fuel expense has increased by $48.2 million, from $723.8 million in the 2016 TAM final update to $772.0 million in the 2017 TAM. All dollar amounts stated in my testimony are on a total-company basis. This increase represents an increase of approximately $18.2

million based on higher coal-fired generation and an increase of approximately $30.0 million based on higher coal prices.

THIRD-PARTY COAL CONTRACTS

Q. Please discuss the change in third-party coal supplies.

A. The Company expects a net decrease in third-party coal supply costs as shown in Confidential Table 2 below:

Confidential Table 2: Coal and Transportation Contract Price Increase/(Decrease)

Plant	Contract	Millions ($)
Naughton	Kemmerer Mine Price	[redacted]
Wyodak	Wyodak Mine Contract Price	
Cholla	Lee Ranch Coal and Rail Cost	
Dave Johnston	BNSF Rail Rate	
Dave Johnston	Powder River Basin Mines Prices	
Hunter	Bowie Coal Cost	
Huntington	Bowie and Castle Valley Coal Cost	
Bridger	Black Butte Coal and Rail Cost	
Colstrip	Rosebud Mine Cost	
Hayden	Twentymile Mine Cost	
Craig	Colowyo Mine Cost	
Total Contract Costs Increase/(Decrease)		

Q. Do any of the third-party coal contracts include minimum take requirements?

A. Yes [redacted] are fueled either partially or entirely with coal supply agreements and/or transportation agreements that contain minimum take-or-pay provisions based on certain annual tonnage volumes of coal delivered. In addition, the [redacted] plant's coal supply agreement and the transportation agreements for the [redacted] plants all provide for payment of liquidated damages below certain minimum volumes.

Q. How do these minimum take requirements impact coal costs?

A. Reductions in coal consumption at plants with minimum take requirements result in relatively small reductions in total coal fuel expense due to take-or-pay contract clauses or liquidated damages. In the Company's initial filing, the following plants generate at or near the minimum requirement in 2017: [redacted]. Because other plants are close to the minimums, the Company will monitor further reductions in generation during the TAM and account for plant minimums, as applicable, in TAM updates.

Coal Supply Agreements for the Wyoming Plants

Naughton

Q. Has the Naughton plant's coal cost changed from the 2016 TAM?

A. Yes. Delivered coal cost at the Naughton plant decreased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, a decrease of [redacted] per ton or [redacted]. The decrease in the price under the Company's contract with the Kemmerer mine was due to automatic adjustments based on changes in contract-specific producer and consumer price indices, as well as production taxes and royalties. Lower diesel fuel, mining machinery and royalties were the primary drivers of [redacted] of the decrease. [redacted] of the decrease is the result of a change in the amount of coal purchased under each price tier, namely more tier-2 coal which is lower priced than tier-1 coal. [redacted] of the reduction in coal price is due to the discontinuation of the amortization of the consideration payment for the settlement of the contract, which was effective July 1, 2010, to December 31, 2016.

Wyodak

Q. Please describe the price increase related to the Wyodak plant contract.

A. Delivered coal cost has increased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, which results in an increase of [redacted]. The cost increase is primarily the result of escalation in labor and other contract indices partially offset by decreases in diesel fuel and power price indices.

Jim Bridger

Q. Please explain the increase in third-party coal prices for the Jim Bridger plant.

A. Jim Bridger plant third-party coal prices increase [redacted], compared to the 2016 TAM. The price of Black Butte coal delivered to the Jim Bridger plant has increased from [redacted] per ton in the 2016 TAM to [redacted] per ton, an increase of [redacted] per ton. The fixed price Black Butte contract price remained the same in 2016 and 2017, but an increase attributable to the Union Pacific Railroad rail agreement caused the approximately [redacted] increase in delivered costs.

Dave Johnston

Q. Does the 2017 TAM reflect a decrease in Dave Johnston plant coal supply costs?

A. Yes. Dave Johnston plant delivered coal cost has decreased by [redacted] compared to the 2016 TAM, or [redacted]. A decline in rail cost of [redacted] is partially offset by an increase in coal cost of approximately [redacted].

Q. Confidential Table 1 includes spot/unidentified coal for the Dave Johnston plant. Please explain.

A. The Dave Johnston plant is projected to consume approximately [redacted] tons in 2017; the Company currently has [redacted] tons of coal for the plant under contract.

The Company intends to solicit multi-year coal supplies from PRB mines through a request for proposals (RFP) during the second quarter of 2016.

Q. What are the coal supply arrangements for the Dave Johnston plant in the 2017 TAM?

A. Following an April 2015 RFP for PRB coal supplies, the Company executed a coal supply agreement for the purchase of additional coal from Cloud Peak Energy's Cordero Rojo mine through 2018. The Cordero Rojo mine will supply [redacted] tons in 2017 (approximately [redacted] percent of the plant's requirements). The coal price for the Dave Johnston plant's open position of approximately [redacted] tons in the 2017 TAM reflects the average 2017 forward price for PRB 8400 Btu coal as published in Coal Daily as of [redacted].

Coal Supply Agreements for the Utah Plants

Q. Please explain how the Company's Utah plants are supplied with coal.

A. The Utah plants are sourced collectively through a portfolio of coal sources under three different multi-year coal supply agreements. The primary coal supply for the Hunter plant is provided through a coal supply agreement with Bowie Coal Sales, LLC (Bowie). This agreement, which was amended as a part of the Deer Creek mine transaction in 2015, expires in December 2020. The agreement is a "delivered to plant" agreement, and Bowie is responsible for the transportation of the coal from the mine to the plant.

With the closure of the Company's Deer Creek mine in 2015, the primary coal supply to the Huntington plant is now provided via a contract with Bowie through 2029. Coal received under this agreement is designated for the Huntington plant.

This is also a "delivered to the plant" agreement.

The Huntington plant also receives coal under a coal supply agreement with Rhino Energy, LLC's Castle Valley mine, which is interchangeable between the Hunter and Huntington plants.

Q. Please discuss the coal supply arrangement with Castle Valley.

A. The Company has a coal supply agreement with Castle Valley mine. The mine is required to supply [redacted] tons of coal annually through 2017 for the Company's Utah plants.

Q. Does the 2017 TAM reflect Energy West pension costs?

A. Yes. As authorized by Order No. 15-161 in docket UM 1712, the 2017 TAM includes [redacted] for contributions to the 1974 United Mine Workers Association pension plan.[1] Approximately [redacted] is included in Huntington plant costs in the 2017 TAM, an increase of [redacted] compared to the 2016 TAM. Approximately [redacted] of the [redacted] in pension costs is included in Hunter plant costs in the 2017 TAM, consistent with the 2016 TAM.

Hunter

Q. Have prices for coal supply to the Hunter plant changed from levels reflected in the 2016 TAM?

A. Yes. Coal prices have increased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, an increase of [redacted] per ton or [redacted]. The increase at the Hunter plant is primarily associated with the price increase for Bowie coal resulting from the January 2016 contract price re-opener which was settled during the

[1] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction*, Order No. 15-161 at 1 (May 27, 2015), *clarified and amended*, Order No. 15-166 (June 1, 2015).

first quarter of 2016. The tier-1 price for the 2016 price re-opener is [redacted] per ton which is [redacted] per ton lower than the 2015 price of [redacted] per ton. The coal cost escalates to [redacted] per ton for the 2017 TAM. This results in an increase of approximately [redacted]. In addition to the price re-opener, reduced generation for the Hunter plant result in reduced volumes of coal delivered and, therefore, there is a further price increase associated with less tier-2 coal under the agreement of approximately [redacted]. Energy West pension costs included in Hunter plant costs have remained the same in the 2017 TAM.

Q. Please describe how the expiration of the West Ridge contract at the end of 2016 affects coal deliveries at the Hunter plant.

A. The Company's current agreement with the West Ridge mine expires at the end of 2016. West Ridge coal has historically been used to manage ash fusion temperature levels at the Hunter plant. Due to reductions in generation in the 2017 TAM, additional coal purchases for the Hunter plant are limited. This reduction in West Ridge coal results in a savings of approximately [redacted] in the 2017 TAM.

Huntington

Q. What coal supply costs for the Huntington plant are included in the 2017 TAM?

A. For the Huntington plant, delivered coal prices increased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, an increase of [redacted] per ton or [redacted]. The overall price per ton for the Bowie contract increased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, an increase of [redacted] per ton or [redacted]. The coal pricing under the Bowie contract is specified fixed pricing for each year under the agreement. The Castle Valley mine price increased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, an increase of [redacted] per ton or [redacted]. The pricing under Castle Valley mine agreement escalates each year based upon an inflation index. In addition, Energy West pension costs increased [redacted] compared to the 2016 TAM. An additional Castle Valley contract for [redacted] tons with pricing at [redacted] per ton included in the 2016 TAM was excluded from the 2017 TAM because the contract expires in 2016.

Coal Supply Agreements for the Jointly Owned Plants

Cholla

Q. Please describe the coal supply arrangements for the Cholla plant.

A. The Cholla plant is supplied under a coal supply agreement with Peabody's Lee Ranch and El Segundo mine complex through 2024, which includes two price re-openers: the first price re-opener was January 1, 2013; the second price re-opener is January 1, 2018.

Q. What price has the Company assumed for the Cholla coal supply in the 2017 TAM?

A. With quarterly escalation and de-escalation based on producer and consumer price indices, the Company forecasts that delivered coal prices at the Cholla plant will decrease from [redacted] per ton in the 2016 TAM to [redacted] per ton in the current 2017 TAM, a reduction of [redacted] per ton or [redacted]. The decrease is mainly attributable to a reduction in diesel fuel and natural gas indices under the agreement, partially offset by increased royalties and taxes.

Hayden

Q. Has the Hayden plant's coal cost changed in the 2017 TAM?

A. Yes. Delivered coal prices have decreased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, a reduction of [redacted] per ton or [redacted]. The contract price adjusts with changes in producer and consumer price indices.

Colstrip

Q. Please explain the decrease in coal fuel expense at the Colstrip plant in the 2017 TAM.

A. Coal prices for the Colstrip plant have decreased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, a decrease of [redacted] per ton or [redacted]. Costs for the Colstrip plant are developed based on Western Energy's Annual Operating Plan (AOP) for the Rosebud mine. The AOP is reviewed and approved annually by the owners of Colstrip Units 3 and 4. The decrease in 2017 is primarily attributable to a decrease in the Rosebud mine's variable production cost.

Craig

Q. Please describe the coal supply arrangements for the Craig plant.

A. The Craig plant is supplied with two coal supply agreements. One agreement is with Tri-State's Colowyo mine through 2017. Pricing under this agreement adjusts quarterly based upon the escalation and de-escalation of specific producer and consumer price indices. The agreement also has a market price adjustment effective July 2016. The other agreement is with the Trapper Mine that runs through 2020. The Trapper mine is a captive mine owned by the owners of the Craig plant. The pricing under the agreement is based upon the annual mine cost associated with the Trapper mine.

Q. Has the Craig plant's third-party coal cost changed from the 2016 TAM?

A. Yes. Delivered coal prices under the Colowyo coal supply agreement have increased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, an increase of [redacted] per ton or [redacted]. The primary reason for the increase is that the estimated market price increase is in effect for only half of 2016 but is in effect for all of 2017.

CAPTIVE MINE COAL COSTS

Q. Please explain the major changes associated with coal costs from PacifiCorp's captive mines in the 2017 TAM.

A. Bridger Coal Company mine costs have increased by [redacted] per ton or [redacted], primarily due to reduced coal production. Trapper mine costs have increased by [redacted] per ton or [redacted], also due to reduced coal production. Energy West pension costs increased [redacted] in the 2017 TAM.

Q. In Order No. 13-387, the Commission ordered the Company to remove certain operations and maintenance costs embedded in the costs of coal from its affiliate mines.[2] Did the Company adjust the price of coal from Bridger Coal Company consistent with Order No. 13-387?

A. Yes. In the 2017 TAM, the Company has reduced Bridger Coal Company costs by approximately [redacted] to reflect removal of management overtime and 50 percent of annual incentive plan (AIP) awards.

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[2] *In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No.13-387 (Oct. 28, 2013).

Bridger Coal Company

Q. Please describe the change in Bridger Coal Company coal costs in the 2017 TAM.

A. Bridger Coal Company costs increased from the 2016 TAM by approximately [redacted]. A significant reduction in coal production contributed to the majority of the cost increase in the 2017 TAM. Bridger Coal Company costs increased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, an increase of [redacted] per ton or [redacted]. A decrease in heat content from [redacted] Btu per pound to [redacted] Btu per pound of coal accounts for [redacted] of the increase.

Q. Please explain the reasons for the significant production decrease at Bridger Coal Company compared to the 2016 TAM.

A. The primary factor contributing to lower coal production and coal deliveries in the 2017 TAM is reduced generation at the Jim Bridger plant. The Company developed the Bridger Coal Company mine production volumes and costs for the 2016 TAM initial filing in April 2015 using a mine plan that supported a consumption level of [redacted] MMBtu at the Jim Bridger plant. In the final update in November 2015, the consumption level at the Jim Bridger plant fell by [redacted] MMBtu to [redacted] MMBtu, primarily due to lower natural gas and power market prices in the Company's official forward price curve. Because the TAM Guidelines do not allow updates for captive coal prices in the final update, however, Bridger Coal Company mine production levels and costs per ton remained unchanged in the 2016 TAM.

The reduction in coal consumed at the Jim Bridger plant without a corresponding price increase at the Bridger Coal Company to mitigate the impact of fixed costs recovered over fewer tons resulted in the Company's net power costs being significantly understated in the 2016 TAM final update, which benefited customers.

The Bridger Coal Company mine plan for the 2017 TAM initial filing was developed using a consumption level of approximately [redacted] MMBtu at the Jim Bridger plant, generally consistent with the consumption level in the 2016 TAM final update. Mr. Dickman provides additional testimony describing the circumstances affecting coal generation in the TAM filings, including reductions in generation at the Jim Bridger plant.

Q. Please explain how Bridger Coal Company's production levels have changed in the 2017 TAM.

A. As reflected in Confidential Table 3 below, Bridger Coal Company's production decreased from [redacted] tons in the 2016 TAM initial filing to [redacted] tons in the 2017 TAM initial filing, a reduction of [redacted], while Bridger Coal Company deliveries decreased from [redacted] tons to [redacted] tons, a reduction of [redacted]. This and all further discussion of Bridger Coal Company cost and volume amounts in the 2016 TAM refer to the April 2015 initial filing.

Confidential Table 3: Bridger Coal Production

[redacted]

Q. How has Bridger Coal Company responded to the reduced demand from the Jim Bridger plant?

A. As noted in Confidential Table 3, Bridger Coal Company reduced coal production at both the surface and underground mines. Surface mine coal production was reduced by [redacted] tons or [redacted] percent. Surface mine coal deliveries were reduced by [redacted] tons or [redacted] percent. Coal production and delivery reductions were achieved by idling the equivalent of one operating dragline and completing [redacted] more cubic yards of final reclamation in the 2017 TAM versus the 2016 TAM. The 2016 TAM assumed both draglines would operate two 12-hour shifts per day, seven days per week. The 2017 TAM assumes the equivalent of one dragline operates two 12-hour shifts per day, seven days per week. The truck/loader, dozer and scraper fleets operate on the same shift schedules in both filings.

Q. If surface mine coal deliveries and dragline shifts worked are reduced from the 2016 TAM, why do mobile fleet shifts worked remain unchanged?

A. Mobile shifts worked remain unchanged from the 2016 TAM because adequate surface mine pre-stripping requirements must be maintained to ensure draglines operate in an uninhibited, efficient manner. Actual pre-stripping amounts have fallen behind the level forecast in the 2016 TAM.

Q. Please explain Bridger Coal Company's reduced production at the underground mine.

A. Underground mine coal production is reduced by [redacted] tons or [redacted] percent. Underground mine coal deliveries are reduced by [redacted] tons or [redacted] percent. Both the 2016 TAM and the 2017 TAM assumed that three continuous miner sections and one longwall section operate during the year.

Q. Please explain why Bridger Coal Company coal costs remain reasonable, even though these costs have increased in the 2017 TAM.

A. The underlying operating costs at Bridger Coal Company have not changed materially. Instead, it is the reduced coal production from both the surface and underground mining operations that has increased delivered costs in the 2017 TAM, because fixed costs are recovered over a smaller volume. In other words, due to reductions in volumes, costs expressed on a per-ton basis have increased. As Mr. Dickman explains, the reduction in coal-fired generation is a function of current low power market prices. At market prices projected in the Company's long-term mine plan, Bridger Coal Company remains a cost-effective source of supply for the Jim Bridger plant.

Q. Please identify the specific costs that increase on a cost-per-ton basis in the face of declining volumes.

A. Primary cost drivers expressed on a cost-per-ton basis for Bridger Coal Company are: (1) increased depreciation; (2) increased royalties; (3) increased final reclamation expense; (4) increased coal inventory expense; and (5) increased labor/benefit, materials/supplies, and outside service expenses.

Q. How have depreciation costs expressed on a cost-per-ton basis increased in the 2017 TAM?

A. Depreciation costs have increased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, an increase of [redacted] per ton. Lower coal deliveries contributed to [redacted] per ton of the increase. The remaining increase of [redacted] per ton is due to an additional year of depreciation between the 2016 TAM and the 2017 TAM.

Q. Why have royalty costs increased in the 2017 TAM?

A. Royalty costs increased from [redacted] in the 2016 TAM to [redacted] per ton in the 2017 TAM, an increase of [redacted] per ton. Although total royalty costs decreased by [redacted], the royalty cost per ton increased due to reduced coal deliveries at both the surface and underground mines. Federal and state royalties are based on a cost plus return valuation methodology; therefore, royalty costs rise as production cost per ton increases.

Q. Please explain how final reclamation contributions expressed on a cost per ton basis increased in the 2017 TAM.

A. Although the final reclamation contribution amount remained unchanged at [redacted] from the 2016 TAM to the 2017 TAM, the cost increased by [redacted] per ton due to fewer tons delivered.

Q. What is the cost increase associated with changes in coal inventory between the 2017 TAM and the 2016 TAM?

A. Approximately [redacted], or [redacted] per ton, can be attributed to changes in Bridger Coal Company's coal inventory. The 2016 TAM reflected an increase in underground inventory levels of [redacted] tons and a projected decrease in surface inventory levels of [redacted] tons. The decrease in inventory levels in the 2016 TAM results in approximately [redacted] being credited to coal inventory and debited to coal expense. The 2017 TAM reflects a decrease in underground inventory levels of [redacted] tons and a decrease in surface inventory levels of [redacted] tons. The decrease in inventory levels in the 2017 TAM results in a credit of [redacted] to coal inventory and a debit to coal expense.

Q. How much have labor and benefit, material and supply, and outside service costs changed in the 2017 TAM?

A. Projected expenditures are [redacted] lower in the 2017 TAM compared to the 2016 TAM. However, costs expressed on a per-ton basis are projected to increase by [redacted] per ton. The cost-per-ton increase is primarily due to delivering 1.1 million less tons in the 2017 TAM versus the 2016 TAM. Total labor and benefit costs decreased by [redacted], material and supply costs decreased by [redacted] and outside service costs decreased by [redacted].

Q. Although the mine delivered fewer tons in the 2017 TAM versus the 2016 TAM, did any cost categories decrease expressed on a cost-per-ton basis?

A. Yes. Expenditures for deferred longwall, final reclamation, severance tax and federal reclamation decrease by a total of [redacted] per ton.

Trapper Mine

Q. Have Trapper mine costs changed from the 2016 TAM?

A. Yes. Trapper mine costs have increased from [redacted] per ton in the 2016 TAM to [redacted] per ton in the 2017 TAM, or [redacted] per ton. This increase is primarily attributable to reduced production at Trapper mine as a result of reduced generation and increased coal stockpile levels at the Craig plant. Deliveries from Trapper mine have decreased from [redacted] tons in the 2016 TAM to [redacted] tons in the 2017 TAM, a reduction of [redacted]. Reduced coal production has a significant impact on delivered costs in the 2017 TAM. Due to the reductions in volumes, costs expressed on a per ton basis have increased.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 307
Exhibit PAC/300
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

April 2016

DIRECT TESTIMONY OF JUDITH M. RIDENOUR

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My current position is Specialist, Pricing and Cost of Service, in the regulation department.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I hold a Bachelor of Arts degree in Mathematics from Reed College. I joined the Company in the regulation department in October 2000. I assumed my present responsibilities in May 2001. In my current position, I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the Company's six-state service territory.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present the Company's proposed rate spread, rates, and revised tariff pages for the 2017 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) and the TAM adjustments for other revenues and federal production tax credits (PTCs) identified by Mr. Brian S. Dickman. I also provide a summary of the impact of the proposed rate change on customers' bills.

PROPOSED RATE SPREAD AND RATE DESIGN

Q. Please describe the Company's tariff rate schedule that collects NPC.

A. The Company collects NPC through Schedule 201, Net Power Costs, Cost-Based

Supply Service. Collecting NPC through a separate rate schedule allows NPC to be more easily and accurately updated through TAM filings.

Q. What is the test period for this TAM?

A. In accordance with the TAM Guidelines adopted in Order No. 09-274,[1] the test period for the TAM is the year during which the Schedule 201 rates will be effective, which is the 12 months ending December 31, 2017.

Q. How did the Company allocate NPC to the rate schedule classes?

A. The Company allocated forecast NPC to the customer classes based on the present spread of NPC revenue, which is consistent with the TAM Guidelines and consistent with the generation allocation factors agreed to the stipulation in the Company's last general rate case, docket UE 263, approved in Order No. 13-474,[2] updated for the change in load.

Q. Did you prepare an exhibit showing the rate spread and present and proposed Schedule 201 rates and revenues?

A. Yes. Exhibit PAC/301 shows present Schedule 201 rates and revenues and the associated rate spread and revenue targets for each rate schedule based on the Oregon-allocated forecast NPC, including the adjustment for non-NPC EIM Costs, identified by Mr. Dickman. The final columns in the exhibit show the proposed Schedule 201 rates and revenues. As explained by Mr. Dickman, forecast NPC is subject to updates throughout this proceeding.

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[1] *In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service*, Docket No. UE 199, Order No. 09-274 (July 16, 2009).
[2] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 263, Order No. 13-474 (December 18, 2013).

Q. Is the proposed Schedule 201 rate design consistent with the TAM Guidelines?

A. Yes. The proposed Schedule 201 rates are designed to collect revenues from rate schedules based on the proposed rate spread described above. Additionally, the rates in the Company's proposed Schedule 201 use the same rate blocks and relationships between rate blocks as the existing Schedule 201 rates.

Q. How does the Company propose to reflect in rates the amounts related to other revenues and PTCs associated with this TAM filing?

A. The Company's Schedule 205, TAM Adjustment for Other Revenues, has been used to collect or distribute the adjustment related to other revenues in a stand-alone TAM filing. The Company proposes to use Schedule 205 to reflect both the adjustment for other revenues and the adjustment related to PTCs.

Present rates for Schedule 205 were established in the Company's 2016 TAM, docket UE 296.[3] The Company proposes adders to the present Schedule 205 rates reflecting the adjustments related to other revenues and PTCs described in Mr. Dickman's testimony. The proposed rate spread and rate design for the Schedule 205 adders parallels the generation-based rate spread and rate design of Schedule 201 for NPC as described above, consistent with past treatment of this adjustment.

The Company proposes to retitle Schedule 205 as TAM Adjustment for Other Items to reflect the inclusion of adjustments related to PTCs in the schedule.

Q. Did you prepare an exhibit showing proposed Schedule 205 rates and revenues?

A. Yes. Exhibit PAC/302 shows the proposed adjustments to Schedule 205 rates and revenues based on the amounts in the 2017 TAM for other revenues and PTCs along

[3] *In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, preliminary Order No. 15-353 (October 26, 2015), final Order No. 15-394 (December 11, 2015).

with the total combined Schedule 205 rates for the tariff, which reflect the present Schedule 205 rates plus the additional adjustments for the 2017 TAM.

Q. Please describe Exhibit PAC/303.

A. Exhibit PAC/303 contains the proposed revised Schedules 201 and 205.

Q. Is the Company proposing changes to its transition adjustment tariff schedules at this time?

A. No. The Company will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—once the final TAM rates have been posted and are known. The Transition Adjustment rates will be established in November, just before the open enrollment window.

COMPARISON OF PRESENT AND PROPOSED CUSTOMER RATES

Q. What are the overall rate effects of the changes proposed in this filing?

A. The overall proposed effect is a rate increase of 1.6 percent on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/304 shows the estimated effect of the Company's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. Did you prepare an exhibit that shows the impact on customer bills as a result of the proposed changes to Schedule 201 and Schedule 205?

A. Yes. Exhibit PAC/304, beginning on page 2, contains monthly billing comparisons for customers at different usage levels served on each of the major delivery service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules including the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. What is the estimated monthly impact to an average residential customer?

A. The estimated monthly impact to the average residential customer using 900 kilowatt-hours per month is a bill increase of $1.38.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 307
Exhibit PAC/301
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Rate Spread and Rates

April 2016

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2017

		Present Schedule 201		Present Rate	Target	Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Spread	Revenues	Rates	Revenues
Schedule 4, Residential							
First Block kWh (0-1,000)	3,866,192,250	2.729 ¢	$105,508,387	29.0330%	$109,469,197	2.831 ¢	$109,451,903
Second Block kWh (> 1,000)	1,363,856,082	3.728 ¢	$50,844,555	13.9910%	$52,753,272	3.868 ¢	$52,753,953
	5,230,048,332		$156,352,942		$162,222,469		$162,205,856
						Change	$5,852,914
Employee Discount							
First Block kWh (0-1,000)	11,175,059	2.729 ¢	$304,967			2.831 ¢	$316,366
Second Block kWh (> 1,000)	5,260,850	3.728 ¢	$196,124			3.868 ¢	$203,490
	16,435,909		$501,091				$519,856
Discount			-$125,273				-$129,964
						Change	-$4,691
Schedule 23, Small General Service							
Secondary Voltage							
1st 3,000 kWh, per kWh	871,764,198	3.023 ¢	$26,353,432	7.2517%	$27,342,746	3.136 ¢	$27,338,525
All additional kWh, per kWh	234,196,016	2.242 ¢	$5,250,675	1.4448%	$5,447,787	2.326 ¢	$5,447,399
	1,105,960,214		$31,604,107		$32,790,533		$32,785,924
						Change	$1,181,817
Primary Voltage							
1st 3,000 kWh, per kWh	738,519	2.928 ¢	$21,624	0.0060%	$22,436	3.038 ¢	$22,436
All additional kWh, per kWh	329,186	2.172 ¢	$7,150	0.0020%	$7,418	2.254 ¢	$7,420
	1,067,705		$28,774		$29,854		$29,856
						Change	$1,082
Schedule 28, General Service 31-200kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	1,427,143,857	2.956 ¢	$42,186,372	11.6085%	$43,770,058	3.067 ¢	$43,770,502
All additional kWh, per kWh	582,416,811	2.875 ¢	$16,744,483	4.6076%	$17,373,075	2.983 ¢	$17,373,493
	2,009,560,668		$58,930,855		$61,143,133		$61,143,995
						Change	$2,213,140
Primary Voltage							
1st 20,000 kWh, per kWh	9,801,024	2.846 ¢	$278,937	0.0768%	$289,408	2.953 ¢	$289,424
All additional kWh, per kWh	8,837,541	2.770 ¢	$244,800	0.0674%	$253,990	2.874 ¢	$253,991
	18,638,565		$523,737		$543,398		$543,415
						Change	$19,678
Schedule 30, General Service 201-999kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	184,702,861	3.160 ¢	$5,836,610	1.6061%	$6,055,718	3.279 ¢	$6,056,407
All additional kWh, per kWh	1,086,874,572	2.740 ¢	$29,780,363	8.1947%	$30,898,325	2.843 ¢	$30,899,844
	1,271,577,433		$35,616,973		$36,954,043		$36,956,251
						Change	$1,339,278
Primary Voltage							
1st 20,000 kWh, per kWh	12,525,631	3.125 ¢	$391,426	0.1077%	$406,120	3.242 ¢	$406,081
All additional kWh, per kWh	80,863,348	2.701 ¢	$2,184,119	0.6010%	$2,266,111	2.802 ¢	$2,265,791
	93,388,979		$2,575,545		$2,672,232		$2,671,872
						Change	$96,327
Schedule 41, Agricultural Pumping Service							
Secondary Voltage							
Winter, 1st 100 kWh/kW, per kWh	2,915,053	4.221 ¢	$123,044	0.0339%	$127,663	4.379 ¢	$127,650
Winter, All additional kWh, per kWh	2,478,448	2.876 ¢	$71,280	0.0196%	$73,956	2.984 ¢	$73,957
Summer, All kWh, per kWh	227,452,860	2.876 ¢	$6,541,544	1.8001%	$6,787,115	2.984 ¢	$6,787,193
	232,846,361		$6,735,868		$6,988,734		$6,988,800
						Change	$252,932
Primary Voltage							
Winter, 1st 100 kWh/kW, per kWh	10,164	4.086 ¢	$415	0.0001%	$431	4.236 ¢	$431
Winter, All additional kWh, per kWh	58,136	2.786 ¢	$1,620	0.0004%	$1,681	2.892 ¢	$1,681
Summer, All kWh, per kWh	361,344	2.786 ¢	$10,067	0.0028%	$10,445	2.892 ¢	$10,450
	429,644		$12,102		$12,556		$12,562
						Change	$460
Schedule 47, Large General Service, Partial Requirements 1,000kW and over							
Primary Voltage							
On-Peak, per on-peak kWh	35,574,864	2.584 ¢	$919,254			2.680 ¢	$953,406
Off-Peak, per off-peak kWh	12,536,048	2.534 ¢	$317,663			2.630 ¢	$329,698
	48,110,912		$1,236,917		$1,283,104		$1,283,104
						Change	$46,187
Transmission Voltage							
On-Peak, per on-peak kWh	49,897,565	2.427 ¢	$1,211,014			2.517 ¢	$1,255,922
Off-Peak, per off-peak kWh	41,971,311	2.377 ¢	$997,658			2.467 ¢	$1,035,432
	91,868,876		$2,208,672		$2,291,354		$2,291,354
						Change	$82,682

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2017

Rate Schedule	Forecast Energy	Present Schedule 201 Rates	Present Schedule 201 Revenues	Present Rate Spread	Target Revenues	Proposed Schedule 201 Rates	Proposed Schedule 201 Revenues
Schedule 48, Large General Service, 1,000kW and over							
Secondary Voltage							
On-Peak, per on-peak kWh	362,578,407	2.787 ¢	$10,105,060	2.7806%	$10,484,406	2.891 ¢	$10,482,142
Off-Peak, per off-peak kWh	199,758,810	2.737 ¢	$5,467,399	1.5045%	$5,672,646	2.841 ¢	$5,675,148
	562,337,217		$15,572,459		$16,157,053		$16,157,290
						Change	$584,831
Primary Voltage							
On-Peak, per on-peak kWh	1,059,842,214	2.584 ¢	$27,386,323	7.5360%	$28,414,412	2.680 ¢	$28,403,771
Off-Peak, per off-peak kWh	666,622,616	2.534 ¢	$16,892,217	4.6483%	$17,526,355	2.630 ¢	$17,532,175
	1,726,464,830		$44,278,540		$45,940,767		$45,935,946
						Change	$1,657,406
Transmission Voltage							
On-Peak, per on-peak kWh	237,834,835	2.427 ¢	$5,772,251	1.5884%	$5,988,943	2.517 ¢	$5,986,303
Off-Peak, per off-peak kWh	181,976,894	2.377 ¢	$4,325,591	1.1903%	$4,487,975	2.467 ¢	$4,489,370
	419,811,729		$10,097,842		$10,476,917		$10,475,673
						Change	$377,831
Schedule 15, Outdoor Area Lighting Service							
Secondary Voltage							
All kWh, per kWh	9,366,492	2.278 ¢	$213,371	0.0587%	$221,381	2.364 ¢	$221,661
	9,366,492		$213,371		$221,381		$221,661
						Change	$8,290
Schedule 50, Mercury Vapor Street Lighting Service							
Secondary Voltage							
All kWh, per kWh	7,781,826	1.877 ¢	$146,352	0.0403%	$151,846	1.951 ¢	$151,652
	7,781,826		$146,352		$151,846		$151,652
						Change	$5,300
Schedule 51, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	19,908,344	2.963 ¢	$589,355	0.1622%	$611,480	3.071 ¢	$610,960
	19,908,344		$589,355		$611,480		$610,960
						Change	$21,605
Schedule 52, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	400,697	2.265 ¢	$9,076	0.0025%	$9,416	2.350 ¢	$9,416
	400,697		$9,076		$9,416		$9,416
						Change	$341
Schedule 53, Street Lighting Service, Consumer-Owned System							
Secondary Voltage							
All kWh, per kWh	9,910,325	0.966 ¢	$95,734	0.0263%	$99,328	1.002 ¢	$99,301
	9,910,325		$95,734		$99,328		$99,301
						Change	$3,568
Schedule 54, Recreational Field Lighting							
Secondary Voltage							
All kWh, per kWh	1,464,102	1.666 ¢	$24,392	0.0067%	$25,308	1.729 ¢	$25,314
	1,464,102		$24,392		$25,308		$25,314
						Change	$922
Total before Employee Discount			**$366,853,612**	100.0000%	$380,624,905		**$380,600,203**
Employee Discount			-$125,273		-$129,964		-$129,964
TOTAL	**12,860,943,252**		**$366,728,340**		$380,494,941		**$380,470,239**
						Change	**$13,741,900**
Schedule 47 Unscheduled kWh	3,131,805						
Total Forecast kWH	12,864,075,057						

Docket No. UE 307
Exhibit PAC/302
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Adjustment for Other Items

April 2016

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Items
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2017

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Generation Based Rate Spread	Proposed Adj. to Schedule 205 for Other Revenues: Rates	Proposed Adj. to Schedule 205 for Other Revenues: Revenues	Proposed Adj. to Schedule 205 for PTC: Rates	Proposed Adj. to Schedule 205 for PTC: Revenues	Total Proposed Schedule 205 Rates
Schedule 4, Residential								
First Block kWh (0-1,000)	3,866,192,250	0.013 ¢	29.0330%	0.009 ¢	$347,957	0.037 ¢	$1,430,491	0.059 ¢
Second Block kWh (> 1,000)	1,363,856,082	0.017 ¢	13.9910%	0.012 ¢	$163,663	0.051 ¢	$695,567	0.080 ¢
	5,230,048,332				$511,620		$2,126,058	
Employee Discount								
First Block kWh (0-1,000)	11,175,059			0.009 ¢	$1,006	0.037 ¢	$4,135	
Second Block kWh (> 1,000)	5,260,850			0.012 ¢	$631	0.051 ¢	$2,683	
	16,435,909				$1,637		$6,818	
Discount					-$409		-$1,705	
Schedule 23, Small General Service								
Secondary Voltage								
1st 3,000 kWh, per kWh	871,764,198	0.014 ¢	7.2517%	0.010 ¢	$87,176	0.041 ¢	$357,423	0.065 ¢
All additional kWh, per kWh	234,196,016	0.011 ¢	1.4448%	0.007 ¢	$16,394	0.030 ¢	$70,259	0.048 ¢
	1,105,960,214				$103,570		$427,682	
Primary Voltage								
1st 3,000 kWh, per kWh	738,519	0.014 ¢	0.0060%	0.009 ¢	$66	0.040 ¢	$295	0.063 ¢
All additional kWh, per kWh	329,186	0.010 ¢	0.0020%	0.007 ¢	$23	0.029 ¢	$95	0.046 ¢
	1,067,705				$89		$390	
Schedule 28, General Service 31-200kW								
Secondary Voltage								
1st 20,000 kWh, per kWh	1,427,143,857	0.014 ¢	11.6085%	0.009 ¢	$128,443	0.040 ¢	$570,858	0.063 ¢
All additional kWh, per kWh	582,416,811	0.013 ¢	4.6076%	0.009 ¢	$52,418	0.039 ¢	$227,143	0.061 ¢
	2,009,560,668				$180,861		$798,001	
Primary Voltage								
1st 20,000 kWh, per kWh	9,801,024	0.014 ¢	0.0768%	0.009 ¢	$882	0.039 ¢	$3,822	0.062 ¢
All additional kWh, per kWh	8,837,541	0.013 ¢	0.0674%	0.009 ¢	$795	0.038 ¢	$3,358	0.060 ¢
	18,638,565				$1,677	0.038	$7,180	
Schedule 30, General Service 201-999kW								
Secondary Voltage								
1st 20,000 kWh, per kWh	184,702,861	0.015 ¢	1.6061%	0.010 ¢	$18,470	0.043 ¢	$79,422	0.068 ¢
All additional kWh, per kWh	1,086,874,572	0.013 ¢	8.1947%	0.009 ¢	$97,819	0.037 ¢	$402,144	0.059 ¢
	1,271,577,433				$116,289		$481,566	
Primary Voltage								
1st 20,000 kWh, per kWh	12,525,631	0.014 ¢	0.1077%	0.010 ¢	$1,253	0.042 ¢	$5,261	0.066 ¢
All additional kWh, per kWh	80,863,348	0.013 ¢	0.6010%	0.009 ¢	$7,278	0.037 ¢	$29,919	0.059 ¢
	93,388,979				$8,531		$35,180	
Schedule 41, Agricultural Pumping Service								
Secondary Voltage								
Winter, 1st 100 kWh/kW, per kWh	2,915,053	0.020 ¢	0.0339%	0.013 ¢	$379	0.057 ¢	$1,662	0.090 ¢
Winter, All additional kWh, per kWh	2,478,448	0.014 ¢	0.0196%	0.009 ¢	$223	0.039 ¢	$967	0.062 ¢
Summer, All kWh, per kWh	227,452,860	0.014 ¢	1.8001%	0.009 ¢	$20,471	0.039 ¢	$88,707	0.062 ¢
	232,846,361				$21,073		$91,336	
Primary Voltage								
Winter, 1st 100 kWh/kW, per kWh	10,164	0.019 ¢	0.0001%	0.013 ¢	$1	0.055 ¢	$6	0.087 ¢
Winter, All additional kWh, per kWh	58,136	0.013 ¢	0.0004%	0.009 ¢	$5	0.038 ¢	$22	0.060 ¢
Summer, All kWh, per kWh	361,344	0.013 ¢	0.0028%	0.009 ¢	$33	0.038 ¢	$137	0.060 ¢
	429,644				$39		$165	
Schedule 47, Large General Service, Partial Requirements 1,000kW and over								
Primary Voltage								
On-Peak, per on-peak kWh	35,574,864	0.012 ¢		0.008 ¢	$2,846	0.035 ¢	$12,451	0.055 ¢
Off-Peak, per off-peak kWh	12,536,048	0.012 ¢		0.008 ¢	$1,003	0.034 ¢	$4,262	0.054 ¢
	48,110,912				$3,849		$16,713	
Transmission Voltage								
On-Peak, per on-peak kWh	49,897,565	0.011 ¢		0.008 ¢	$3,992	0.033 ¢	$16,466	0.052 ¢
Off-Peak, per off-peak kWh	41,971,311	0.011 ¢		0.008 ¢	$3,358	0.032 ¢	$13,431	0.051 ¢
	91,868,876				$7,350		$29,897	

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Items
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2017

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Generation Based Rate Spread	Proposed Adj. to Schedule 205 for Other Revenues: Rates	Proposed Adj. to Schedule 205 for Other Revenues: Revenues	Proposed Adj. to Schedule 205 for PTC: Rates	Proposed Adj. to Schedule 205 for PTC: Revenues	Total Proposed Schedule 205 Rates
Schedule 48, Large General Service, 1,000kW and over								
Secondary Voltage								
On-Peak, per on-peak kWh	362,578,407	0.013 ¢	2.7806%	0.009 ¢	$32,632	0.038 ¢	$137,780	0.060 ¢
Off-Peak, per off-peak kWh	199,758,810	0.013 ¢	1.5045%	0.009 ¢	$17,978	0.037 ¢	$73,911	0.059 ¢
	562,337,217				$50,610		$211,691	
Primary Voltage								
On-Peak, per on-peak kWh	1,059,842,214	0.012 ¢	7.5360%	0.008 ¢	$84,787	0.035 ¢	$370,945	0.055 ¢
Off-Peak, per off-peak kWh	666,622,616	0.012 ¢	4.6483%	0.008 ¢	$53,330	0.034 ¢	$226,652	0.054 ¢
	1,726,464,830				$138,117		$597,597	
Transmission Voltage								
On-Peak, per on-peak kWh	237,834,835	0.011 ¢	1.5884%	0.008 ¢	$19,027	0.033 ¢	$78,485	0.052 ¢
Off-Peak, per off-peak kWh	181,976,894	0.011 ¢	1.1903%	0.008 ¢	$14,558	0.032 ¢	$58,233	0.051 ¢
	419,811,729				$33,585		$136,718	
Schedule 15, Outdoor Area Lighting Service								
Secondary Voltage								
All kWh, per kWh	9,366,492	0.011 ¢	0.0587%	0.007 ¢	$656	0.031 ¢	$2,904	0.049 ¢
	9,366,492				$656		$2,904	
Schedule 50, Mercury Vapor Street Lighting Service								
Secondary Voltage								
All kWh, per kWh	7,781,826	0.009 ¢	0.0403%	0.006 ¢	$467	0.026 ¢	$2,023	0.041 ¢
	7,781,826				$467		$2,023	
Schedule 51, Street Lighting Service, Company-Owned System								
Secondary Voltage								
All kWh, per kWh	19,908,344	0.013 ¢	0.1622%	0.009 ¢	$1,792	0.040 ¢	$7,963	0.062 ¢
	19,908,344				$1,792		$7,963	
Schedule 52, Street Lighting Service, Company-Owned System								
Secondary Voltage								
All kWh, per kWh	400,697	0.011 ¢	0.0025%	0.007 ¢	$28	0.031 ¢	$124	0.049 ¢
	400,697				$28		$124	
Schedule 53, Street Lighting Service, Consumer-Owned System								
Secondary Voltage								
All kWh, per kWh	9,910,325	0.005 ¢	0.0263%	0.003 ¢	$297	0.013 ¢	$1,288	0.021 ¢
	9,910,325				$297		$1,288	
Schedule 54, Recreational Field Lighting								
Secondary Voltage								
All kWh, per kWh	1,464,102	0.007 ¢	0.0067%	0.005 ¢	$73	0.023 ¢	$337	0.035 ¢
	1,464,102				$73		$337	
Total before Employee Discount			**100.0000%**		**$1,180,573**		**$4,974,813**	
Employee Discount					-$409		-$1,705	
TOTAL	**12,860,943,252**				**$1,180,164**		**$4,973,109**	
Schedule 47 Unscheduled kWh	3,131,805							
Total Forecast kWH	12,864,075,057							

Docket No. UE 307
Exhibit PAC/303
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedules

April 2016

Schedule No.

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-275, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Monthly Billing

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0-1000 kWh	2.831¢			(I)
		> 1000 kWh	3.868¢			(I)
5	Per kWh	0-1000 kWh	2.831¢			(I)
		> 1000 kWh	3.868¢			(I)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

		Secondary	**Primary**	**Transmission**	
23	First 3,000 kWh, per kWh	3.136¢	3.038¢		(I)
	All additional kWh, per kWh	2.326¢	2.254¢		(I)
28	First 20,000 kWh, per kWh	3.067¢	2.953¢		(I)
	All additional kWh, per kWh	2.983¢	2.874¢		(I)
30	First 20,000 kWh, per kWh	3.279¢	3.242¢		(I)
	All additional kWh, per kWh	2.843¢	2.802¢		(I)
41	Winter, first 100 kWh/kW, per kWh	4.379¢	4.236¢		(I)
	Winter, all additional kWh, per kWh	2.984¢	2.892¢		(I)
	Summer, all kWh, per kWh	2.984¢	2.892¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Secondary	Primary	Transmission	
		Delivery Voltage			
47/48	Per kWh On-Peak	2.891¢	2.680¢	2.517¢	(I)
	Per kWh, Off-Peak	2.841¢	2.630¢	2.467¢	(I)

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

52	For dusk to dawn operation, per kWh	2.350¢	(I)
	For dusk to midnight operation, per kWh	2.350¢	(I)
54	Per kWh	1.729¢	(I)

15	Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
	Mercury Vapor	7,000	76	$ 1.80	(I)
	Mercury Vapor	21,000	172	$ 4.07	(I)
	Mercury Vapor	55,000	412	$ 9.74	(I)
	High Pressure Sodium	5,800	31	$ 0.73	(I)
	High Pressure Sodium	22,000	85	$ 2.01	(I)
	High Pressure Sodium	50,000	176	$ 4.16	(I)

50 **A. Company-owned Overhead System**

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
Horizontal, per lamp	$1.48	$3.36	$8.04	(I)
Vertical, per lamp	$1.48	$3.36		(I)

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.48			(I)
On 26-foot poles, vertical, per lamp	$1.48			(I)
On 30-foot poles, horizontal, per lamp		$3.36		(I)
On 30-foot poles, vertical, per lamp		$3.36		(I)
On 33-foot poles, horizontal, per lamp			$8.04	(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.48			(I)
On 26-foot poles, vertical, per lamp	$1.48			(I)
On 30-foot poles, horizontal, per lamp		$3.36		(I)
On 30-foot poles, vertical, per lamp		$3.36		(I)
On 33-foot poles, horizontal, per lamp			$8.04	(I)

51

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
LED	4,000	100 (comp)		$0.58	(I)
LED	6,200	150 (comp)		$0.83	(I)
LED	13,000	250 (comp)		$1.57	(I)
LED	16,800	400 (comp)		$2.12	(I)
High Pressure Sodium	5,800	70	31	$0.95	(I)
High Pressure Sodium	9,500	100	44	$1.35	(I)
High Pressure Sodium	16,000	150	64	$1.97	(I)
High Pressure Sodium	22,000	200	85	$2.61	(I)
High Pressure Sodium	27,500	250	115	$3.53	(I)
High Pressure Sodium	50,000	400	176	$5.40	(I)
Metal Halide	12,000	175	68	$2.09	(I)
Metal Halide	19,500	250	94	$2.89	(I)

53

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.31	(I)
High Pressure Sodium	9,500	100	44	$0.44	(I)
High Pressure Sodium	16,000	150	64	$0.64	(I)
High Pressure Sodium	22,000	200	85	$0.85	(I)
High Pressure Sodium	27,500	250	115	$1.15	(I)
High Pressure Sodium	50,000	400	176	$1.76	(I)
Metal Halide	9,000	100	39	$0.39	(I)
Metal Halide	12,000	175	68	$0.68	(I)
Metal Halide	19,500	250	94	$0.94	(I)
Metal Halide	32,000	400	149	$1.49	(I)
Metal Halide	107,800	1,000	354	$3.55	(I)

Non-Listed Luminaire, per kWh 1.002¢ (I)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

TAM ADJUSTMENT FOR OTHER ITEMS (C)

Purpose

This schedule adjusts rates for Other Revenues as authorized by Order No. 10-363 and for Production Tax Credits as authorized by Order No. 16-xxx. (N) (N)

Applicable

To all Residential Consumers and Nonresidential Consumers.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule and Direct Access Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0-1000 kWh	0.059¢			(I)
		> 1000 kWh	0.080¢			(I)
5	Per kWh	0-1000 kWh	0.059¢			(I)
		> 1000 kWh	0.080¢			(I)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

		Secondary	Primary	Transmission	
23, 723	First 3,000 kWh, per kWh	0.065¢	0.063¢		(I)
	All additional kWh, per kWh	0.048¢	0.046¢		(I)
28, 728	First 20,000 kWh, per kWh	0.063¢	0.062¢		(I)
	All additional kWh, per kWh	0.061¢	0.060¢		(I)
30, 730	First 20,000 kWh, per kWh	0.068¢	0.066¢		(I)
	All additional kWh, per kWh	0.059¢	0.059¢		(I)
41, 741	Winter, first 100 kWh/kW, per kWh	0.090¢	0.087¢		(I)
	Winter, all additional kWh, per kWh	0.062¢	0.060¢		(I)
	Summer, all kWh, per kWh	0.062¢	0.060¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Energy Charge (continued)

Delivery Service Schedule No.		Delivery Voltage Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	0.060¢	0.055¢	0.052¢	(I)
747/748	Per kWh, Off-Peak	0.059¢	0.054¢	0.051¢	(I)

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

52, 752	For dusk to dawn operation, per kWh	0.049¢	(I)
	For dusk to midnight operation, per kWh	0.049¢	(I)
54,754	Per kWh	0.035¢	(I)

15	Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
	Mercury Vapor	7,000	76	$0.04	(I)
	Mercury Vapor	21,000	172	$0.08	(I)
	Mercury Vapor	55,000	412	$0.20	(I)
	High Pressure Sodium	5,800	31	$0.02	(I)
	High Pressure Sodium	22,000	85	$0.04	(I)
	High Pressure Sodium	50,000	176	$0.09	(I)

50 **A. Company-owned Overhead System**

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
Horizontal, per lamp	$0.03	$0.07	$0.17	(I)
Vertical, per lamp	$0.03	$0.07		(I)

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$0.03			(I)
On 26-foot poles, vertical, per lamp	$0.03			(I)
On 30-foot poles, horizontal, per lamp		$0.07		(I)
On 30-foot poles, vertical, per lamp		$0.07		(I)
On 33-foot poles, horizontal, per lamp			$0.17	(I)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

Energy Charge (continued)

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$0.03			(I)
On 26-foot poles, vertical, per lamp	$0.03			(I)
On 30-foot poles, horizontal, per lamp		$0.07		(I)
On 30-foot poles, vertical, per lamp		$0.07		(I)
On 33-foot poles, horizontal, per lamp			$0.17	(I)

51, 751 Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
LED	4,000	100 (comp)		$0.01	(I)
LED	6,200	150 (comp)		$0.02	(I)
LED	13,000	250 (comp)		$0.03	(I)
LED	16,800	400 (comp)		$0.04	(I)
High Pressure Sodium	5,800	70	31	$0.02	(I)
High Pressure Sodium	9,500	100	44	$0.03	(I)
High Pressure Sodium	16,000	150	64	$0.04	(I)
High Pressure Sodium	22,000	200	85	$0.05	(I)
High Pressure Sodium	27,500	250	115	$0.07	(I)
High Pressure Sodium	50,000	400	176	$0.11	(I)
Metal Halide	12,000	175	68	$0.04	(I)
Metal Halide	19,500	250	94	$0.06	(I)

53, 753 Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.01	(I)
High Pressure Sodium	9,500	100	44	$0.01	(I)
High Pressure Sodium	16,000	150	64	$0.01	(I)
High Pressure Sodium	22,000	200	85	$0.02	(I)
High Pressure Sodium	27,500	250	115	$0.02	(I)
High Pressure Sodium	50,000	400	176	$0.04	(I)
Metal Halide	9,000	100	39	$0.01	(I)
Metal Halide	12,000	175	68	$0.01	(I)
Metal Halide	19,500	250	94	$0.02	(I)
Metal Halide	32,000	400	149	$0.03	(I)
Metal Halide	107,800	1,000	354	$0.07	(I)

Non-Listed Luminaire, per kWh 0.021¢ (I)

Docket No. UE 307
Exhibit PAC/304
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed TAM Price Change

April 2016

TAM

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDING DECEMBER 31, 2017

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders1	Net Rates	Base Rates	Adders1	Net Rates	($000)	%2	($000)	%2	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	490,463	5,230,048	$597,765	$7,793	$605,558	$606,256	$7,793	$614,049	$8,491	1.4%	$8,491	1.4%	1
2	**Total Residential**		490,463	5,230,048	$597,765	$7,793	$605,558	$606,256	$7,793	$614,049	$8,491	1.4%	$8,491	1.4%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	78,294	1,107,028	$121,654	$5,447	$127,101	$123,369	$5,447	$128,816	$1,715	1.4%	$1,715	1.4%	3
4	Gen. Svc. 31 - 200 kW	28	9,997	2,028,199	$183,967	$3,873	$187,840	$187,188	$3,873	$191,061	$3,221	1.8%	$3,221	1.7%	4
5	Gen. Svc. 201 - 999 kW	30	810	1,364,966	$110,135	$1,542	$111,677	$112,212	$1,542	$113,754	$2,077	1.9%	$2,077	1.9%	5
6	Large General Service >= 1,000 kW	48	187	2,708,614	$193,506	($6,456)	$187,050	$197,295	($6,456)	$190,839	$3,789	1.9%	$3,789	2.0%	6
7	Partial Req. Svc. >= 1,000 kW	47	7	143,112	$12,104	($418)	$11,686	$12,291	($418)	$11,873	$187	1.9%	$187	2.0%	7
8	Agricultural Pumping Service	41	7,950	233,276	$26,924	($1,183)	$25,741	$27,290	($1,183)	$26,107	$366	1.4%	$366	1.4%	8
9	**Total Commercial & Industrial**		97,245	7,585,195	$648,290	$2,805	$651,095	$659,645	$2,805	$662,450	$11,355	1.8%	$11,355	1.7%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,424	9,366	$1,203	$227	$1,430	$1,214	$227	$1,441	$11	0.9%	$11	0.8%	10
11	Street Lighting Service	50	227	7,782	$864	$174	$1,038	$871	$174	$1,045	$7	0.8%	$7	0.7%	11
12	Street Lighting Service HPS	51	781	19,908	$3,488	$731	$4,219	$3,519	$731	$4,250	$31	0.9%	$31	0.7%	12
13	Street Lighting Service	52	35	401	$52	$9	$61	$53	$9	$62	$1	1.9%	$1	1.6%	13
14	Street Lighting Service	53	257	9,910	$622	$126	$748	$627	$126	$753	$5	0.8%	$5	0.7%	14
15	Recreational Field Lighting	54	107	1,464	$121	$23	$144	$122	$23	$145	$1	0.8%	$1	0.7%	15
16	**Total Public Street Lighting**		7,831	48,831	$6,350	$1,290	$7,640	$6,406	$1,290	$7,696	$56	0.9%	$56	0.7%	16
17	**Total Sales before Emp. Disc. & AGA**		595,539	12,864,074	$1,252,405	$11,888	$1,264,293	$1,272,307	$11,888	$1,284,195	$19,902	1.6%	$19,902	1.6%	17
18	Employee Discount				($464)	($3)	($467)	($471)	($3)	($474)	($7)		($7)		18
19	**Total Sales with Emp. Disc**		595,539	12,864,074	$1,251,941	$11,885	$1,263,826	$1,271,836	$11,885	$1,283,721	$19,895	1.6%	$19,895	1.6%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		595,539	12,864,074	$1,254,380	$11,885	$1,266,265	$1,274,275	$11,885	$1,286,160	$19,895	1.6%	$19,895	1.6%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$20.25	$20.41	$0.16	0.79%
200	$29.86	$30.17	$0.31	1.04%
300	$39.49	$39.96	$0.47	1.19%
400	$49.12	$49.73	$0.61	1.24%
500	$58.75	$59.52	$0.77	1.31%
600	$68.37	$69.29	$0.92	1.35%
700	$78.00	$79.07	$1.07	1.37%
800	$87.63	$88.85	$1.22	1.39%
900	**$97.24**	**$98.62**	**$1.38**	**1.42%**
950	$102.07	$103.51	$1.44	1.41%
1,000	$106.87	$108.40	$1.53	1.43%
1,100	$119.60	$121.33	$1.73	1.45%
1,200	$132.31	$134.26	$1.95	1.47%
1,300	$145.04	$147.19	$2.15	1.48%
1,400	$157.77	$160.13	$2.36	1.50%
1,500	$170.50	$173.06	$2.56	1.50%
1,600	$183.21	$185.99	$2.78	1.52%
2,000	$234.11	$237.72	$3.61	1.54%
3,000	$361.34	$367.05	$5.71	1.58%
4,000	$488.58	$496.38	$7.80	1.60%
5,000	$615.82	$625.70	$9.88	1.60%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

kW		Monthly Billing*				Percent	
		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$71	$80	$72	$81	1.18%	1.06%
	750	$98	$107	$99	$108	1.30%	1.18%
	1,000	$125	$133	$126	$135	1.36%	1.27%
	1,500	$178	$187	$181	$189	1.42%	1.35%
10	1,000	$125	$133	$126	$135	1.36%	1.27%
	2,000	$231	$240	$235	$244	1.46%	1.41%
	3,000	$338	$347	$343	$352	1.50%	1.46%
	4,000	$428	$437	$435	$444	1.47%	1.45%
20	4,000	$455	$464	$462	$470	1.39%	1.36%
	6,000	$636	$645	$645	$654	1.39%	1.36%
	8,000	$817	$825	$828	$837	1.38%	1.37%
	10,000	$997	$1,006	$1,011	$1,020	1.38%	1.37%
30	9,000	$961	$970	$973	$982	1.31%	1.29%
	12,000	$1,232	$1,241	$1,248	$1,257	1.32%	1.31%
	15,000	$1,503	$1,512	$1,523	$1,532	1.33%	1.33%
	18,000	$1,774	$1,783	$1,798	$1,806	1.34%	1.33%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

kW		Monthly Billing*				Percent	
		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$70	$79	$71	$79	1.16%	1.04%
	750	$96	$105	$97	$106	1.28%	1.18%
	1,000	$122	$131	$123	$132	1.35%	1.26%
	1,500	$174	$183	$176	$185	1.41%	1.35%
10	1,000	$122	$131	$123	$132	1.35%	1.26%
	2,000	$226	$234	$229	$238	1.45%	1.39%
	3,000	$330	$338	$334	$343	1.49%	1.45%
	4,000	$418	$426	$424	$432	1.47%	1.44%
20	4,000	$444	$453	$450	$459	1.38%	1.35%
	6,000	$620	$629	$628	$637	1.38%	1.36%
	8,000	$796	$805	$807	$815	1.38%	1.37%
	10,000	$972	$980	$985	$994	1.38%	1.37%
30	9,000	$936	$945	$949	$957	1.30%	1.29%
	12,000	$1,200	$1,209	$1,216	$1,225	1.32%	1.31%
	15,000	$1,464	$1,473	$1,484	$1,492	1.33%	1.32%
	18,000	$1,728	$1,737	$1,751	$1,760	1.34%	1.33%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	3,000	$347	$352	1.42%
	4,500	$458	$465	1.62%
	7,500	$680	$692	1.82%
31	6,200	$697	$707	1.47%
	9,300	$927	$942	1.65%
	15,500	$1,386	$1,411	1.84%
40	8,000	$894	$907	1.47%
	12,000	$1,190	$1,210	1.66%
	20,000	$1,783	$1,816	1.85%
60	12,000	$1,332	$1,352	1.48%
	18,000	$1,777	$1,807	1.67%
	30,000	$2,649	$2,698	1.85%
80	16,000	$1,765	$1,791	1.49%
	24,000	$2,351	$2,390	1.68%
	40,000	$3,509	$3,574	1.85%
100	20,000	$2,197	$2,230	1.50%
	30,000	$2,921	$2,970	1.68%
	50,000	$4,369	$4,450	1.86%
200	40,000	$4,302	$4,367	1.51%
	60,000	$5,750	$5,847	1.69%
	100,000	$8,646	$8,807	1.87%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$445	$453	1.61%
	6,000	$547	$556	1.75%
	7,500	$648	$660	1.85%
31	9,300	$894	$909	1.66%
	12,400	$1,104	$1,123	1.79%
	15,500	$1,313	$1,338	1.89%
40	12,000	$1,146	$1,166	1.67%
	16,000	$1,417	$1,442	1.80%
	20,000	$1,687	$1,719	1.89%
60	18,000	$1,709	$1,738	1.68%
	24,000	$2,108	$2,147	1.81%
	30,000	$2,504	$2,552	1.90%
80	24,000	$2,259	$2,297	1.69%
	32,000	$2,786	$2,837	1.82%
	40,000	$3,314	$3,377	1.90%
100	30,000	$2,805	$2,852	1.69%
	40,000	$3,464	$3,528	1.82%
	50,000	$4,124	$4,203	1.91%
200	60,000	$5,500	$5,594	1.71%
	80,000	$6,819	$6,944	1.84%
	100,000	$8,138	$8,294	1.92%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,622	$2,658	1.35%
	30,000	$3,209	$3,260	1.58%
	50,000	$4,382	$4,463	1.86%
200	40,000	$4,603	$4,669	1.44%
	60,000	$5,776	$5,872	1.68%
	100,000	$8,121	$8,280	1.95%
300	60,000	$6,753	$6,850	1.43%
	90,000	$8,512	$8,655	1.68%
	150,000	$12,031	$12,266	1.95%
400	80,000	$8,785	$8,913	1.45%
	120,000	$11,131	$11,320	1.70%
	200,000	$15,822	$16,134	1.97%
500	100,000	$10,848	$11,006	1.46%
	150,000	$13,780	$14,015	1.70%
	250,000	$19,645	$20,033	1.98%
600	120,000	$12,911	$13,100	1.46%
	180,000	$16,429	$16,710	1.71%
	300,000	$23,467	$23,932	1.98%
800	160,000	$17,036	$17,287	1.47%
	240,000	$21,728	$22,101	1.72%
	400,000	$31,111	$31,730	1.99%
1000	200,000	$21,162	$21,474	1.47%
	300,000	$27,026	$27,492	1.72%
	500,000	$38,755	$39,528	1.99%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$3,147	$3,197	1.59%
	40,000	$3,722	$3,787	1.75%
	50,000	$4,297	$4,377	1.87%
200	60,000	$5,666	$5,762	1.68%
	80,000	$6,817	$6,943	1.84%
	100,000	$7,967	$8,123	1.96%
300	90,000	$8,346	$8,487	1.69%
	120,000	$10,072	$10,258	1.85%
	150,000	$11,797	$12,029	1.96%
400	120,000	$10,931	$11,117	1.70%
	160,000	$13,231	$13,478	1.87%
	200,000	$15,532	$15,840	1.98%
500	150,000	$13,528	$13,759	1.71%
	200,000	$16,404	$16,711	1.87%
	250,000	$19,280	$19,663	1.99%
600	180,000	$16,125	$16,402	1.72%
	240,000	$19,576	$19,944	1.88%
	300,000	$23,027	$23,486	1.99%
800	240,000	$21,319	$21,687	1.73%
	320,000	$25,921	$26,410	1.89%
	400,000	$30,522	$31,133	2.00%
1000	300,000	$26,513	$26,972	1.73%
	400,000	$32,265	$32,875	1.89%
	500,000	$38,017	$38,779	2.00%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$190	$218	$155	$193	$222	$155	1.70%	1.82%	0.00%
	3,000	$285	$313	$155	$290	$318	$155	1.69%	1.78%	0.00%
	5,000	$474	$503	$155	$483	$511	$155	1.69%	1.75%	0.00%
Three Phase										
20	4,000	$380	$436	$309	$386	$444	$309	1.69%	1.82%	0.00%
	6,000	$569	$626	$309	$579	$637	$309	1.69%	1.78%	0.00%
	10,000	$949	$1,005	$309	$965	$1,023	$309	1.69%	1.75%	0.00%
100	20,000	$1,898	$2,179	$1,349	$1,930	$2,218	$1,349	1.69%	1.82%	0.00%
	30,000	$2,847	$3,128	$1,349	$2,895	$3,183	$1,349	1.69%	1.78%	0.00%
	50,000	$4,745	$5,026	$1,349	$4,825	$5,113	$1,349	1.69%	1.75%	0.00%
300	60,000	$5,694	$6,536	$3,409	$5,790	$6,654	$3,409	1.69%	1.82%	0.00%
	90,000	$8,541	$9,383	$3,409	$8,685	$9,550	$3,409	1.69%	1.78%	0.00%
	150,000	$14,234	$15,077	$3,409	$14,476	$15,340	$3,409	1.69%	1.75%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$276	$303	$155	$280	$308	$155	1.72%	1.78%	0.00%
	4,000	$367	$395	$155	$374	$402	$155	1.72%	1.77%	0.00%
	5,000	$459	$487	$155	$467	$495	$155	1.72%	1.76%	0.00%
Three Phase										
20	6,000	$551	$606	$309	$561	$616	$309	1.72%	1.78%	0.00%
	8,000	$735	$789	$309	$748	$803	$309	1.71%	1.77%	0.00%
	10,000	$919	$973	$309	$934	$990	$309	1.72%	1.76%	0.00%
100	30,000	$2,756	$3,028	$1,339	$2,803	$3,082	$1,339	1.72%	1.78%	0.00%
	40,000	$3,675	$3,947	$1,339	$3,738	$4,016	$1,339	1.72%	1.77%	0.00%
	50,000	$4,593	$4,865	$1,339	$4,672	$4,951	$1,339	1.72%	1.76%	0.00%
300	90,000	$8,268	$9,084	$3,399	$8,410	$9,246	$3,399	1.72%	1.78%	0.00%
	120,000	$11,024	$11,840	$3,399	$11,213	$12,049	$3,399	1.72%	1.77%	0.00%
	150,000	$13,780	$14,596	$3,399	$14,017	$14,853	$3,399	1.72%	1.76%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Proposed Price	Percent Difference
1,000	300,000	$26,399	$26,864	1.76%
	500,000	$37,660	$38,436	2.06%
	650,000	$46,106	$47,114	2.19%
2,000	600,000	$52,365	$53,296	1.78%
	1,000,000	$73,507	$75,059	2.11%
	1,300,000	$89,835	$91,852	2.25%
6,000	1,800,000	$153,427	$156,220	1.82%
	3,000,000	$218,739	$223,393	2.13%
	3,900,000	$267,722	$273,773	2.26%
12,000	3,600,000	$305,531	$311,117	1.83%
	6,000,000	$436,153	$445,463	2.13%
	7,800,000	$534,120	$546,223	2.27%

Notes:

On-Peak kWh	64.48%
Off-Peak kWh	35.52%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$24,948	$25,376	1.72%
	500,000	$35,393	$36,107	2.02%
	650,000	$43,227	$44,155	2.15%
2,000	600,000	$49,423	$50,279	1.73%
	1,000,000	$68,933	$70,361	2.07%
	1,300,000	$84,037	$85,893	2.21%
6,000	1,800,000	$144,199	$146,769	1.78%
	3,000,000	$204,614	$208,898	2.09%
	3,900,000	$249,926	$255,494	2.23%
12,000	3,600,000	$287,043	$292,183	1.79%
	6,000,000	$407,874	$416,440	2.10%
	7,800,000	$498,497	$509,633	2.23%

Notes:

On-Peak kWh	61.39%
Off-Peak kWh	38.61%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing: Present Price	Monthly Billing: Proposed Price	Percent Difference
1,000	500,000	$35,086	$35,758	1.92%
	650,000	$42,370	$43,244	2.06%
2,000	1,000,000	$67,906	$69,251	1.98%
	1,300,000	$81,910	$83,659	2.13%
6,000	3,000,000	$201,708	$205,742	2.00%
	3,900,000	$243,722	$248,967	2.15%
12,000	6,000,000	$401,268	$409,337	2.01%
	7,800,000	$485,295	$495,785	2.16%
50,000	25,000,000	$1,665,146	$1,698,767	2.02%
	32,500,000	$2,015,262	$2,058,969	2.17%

Notes:

On-Peak kWh	56.65%
Off-Peak kWh	43.35%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.