PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 1, 2014

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
3930 Fairview Industrial Dr. S.E.
Salem, OR 97302-1166

Attn: Filing Center

Re: Advice No. 14-006
Docket UE ____ PacifiCorp's 2015 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, 2015.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2015 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. The TAM Guidelines adopted in Commission Order No. 09-274 specify that if the TAM is filed in a year in which PacifiCorp does not file a general rate case, then the TAM must be filed by April 1 to allow for a January 1 rate effective date. Accordingly, the Company is filing the 2015 TAM on April 1, 2014. This tariff filing is supported by testimony and exhibits from the following witnesses:

- Brian S. Dickman, Manager, Net Power Costs
- Cindy A. Crane, Vice President, Interwest Mining Company and Fuel Resources
- Judith M. Ridenour, Specialist, Cost of Service and Pricing

B. Tariff Sheets

Fifth Revision of Sheet No. 201-1	Schedule 201	Net Power Costs – Cost-Based Supply Service
Fourth Revision of Sheet No. 201-2	Schedule 201	Net Power Costs – Cost-Based Supply Service
Fifth Revision of Sheet No. 201-3	Schedule 201	Net Power Costs – Cost-Based Supply Service
Third Revision of Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Revenues
Second Revision of Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Revenues
Third Revision of Sheet No. 205-3	Schedule 205	TAM Adjustment for Other Revenues

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 Gary Tawwater, Regulatory Affairs Manager, at (503) 813-6805.

A copy of this filing has been served on all parties to PacifiCorp's 2014 TAM proceeding, docket UE 264, as indicated on the attached certificate of service. Confidential material in support of the filing has been provided to parties under Order No. 10-069, the standing protective order adopted for all TAM proceedings.

Sincerely,

R. Bryce Dalley / GWT

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: UE 264 Service List

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's 2015 Transition Adjustment Mechanism on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

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Dated this 1st of April 2014.

Carrie Meyer
Supervisor, Regulatory Operations

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Brian S. Dickman

April 2014

DIRECT TESTIMONY OF BRIAN S. DICKMAN

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ATTACHED EXHIBITS

Exhibit 101—Oregon-Allocated Net Power Costs

Exhibit 102—Net Power Costs Report

Exhibit 103—Update to Other Revenues

Exhibit 104—List of Expected or Known Contract Updates

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 Manager, Net Power Costs.

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, 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 2015 Transition Adjustment Mechanism (TAM) net power costs (NPC). Specifically, my testimony:

- Summarizes the content of the filing.

- Defines NPC and describes the primary drivers behind the increase in total-company NPC for 2015 compared to the final NPC in the Company's previous TAM, docket UE 264 (2014 TAM).[1]
- Describes the Company's implementation of the Commission order from the 2014 TAM and identifies refinements to the modeling of NPC in the 2015 TAM.
- Describes how the filing is consistent with the TAM Guidelines.

Q. Please identify the other Company witnesses supporting the 2015 TAM.

A. Two additional Company witnesses provide testimony supporting the Company's filing. Ms. Cindy A. Crane, Vice President, Interwest Mining & Fuels, provides testimony supporting the coal costs included in the 2015 test period. Ms. Crane also discusses the Company's plans to develop periodic fuel supply plans in accordance with the 2014 TAM order. 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 2015 TAM FILING

Q. Please provide background on the Company's 2015 TAM filing.

A. The TAM is the Company's annual filing to update its NPC in rates. The updated NPC are used to set the transition adjustments for direct access customers and, in this case, become effective in base rates on January 1, 2015. The Company is filing the 2015 TAM on a stand-alone basis without a general rate case. As

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

explained in Ms. Ridenour's testimony, the 2015 TAM results in an overall average rate increase of approximately $18.3 million, or 1.5 percent.

Q. What are the estimated Oregon-allocated NPC for calendar year 2015?

A. As shown on Exhibit PAC/101, on an Oregon-allocated basis, the forecasted normalized NPC for calendar year 2015 are $378.3 million. This is approximately $17.1 million higher than the Oregon-allocated NPC of $361.1 million from the 2014 TAM.

Q. What are the forecasted normalized total-company NPC for calendar year 2015?

A. The total forecasted normalized total-company NPC for calendar year 2015 are $1.530 billion. This is approximately $81.2 million higher than the $1.449 billion reflected in the 2014 TAM. Details of the total-company NPC are provided in Exhibit PAC/102.

Q. Does the proposed rate increase reflect changes in Oregon load since the 2014 TAM?

A. Yes. The 2015 load forecast used in the Company's calculation of NPC reflects a decrease in Oregon load compared to the 2014 forecast loads from the 2014 TAM. Due to the decreased Oregon load, the Company will collect $1.9 million less for NPC based on the rates approved in the 2014 TAM, adding to the overall rate change for the 2015 TAM.

Q. Have Oregon's allocation factors changed since the 2014 TAM?

A. Yes. The reduction in projected Oregon load, coupled with a net increase in total-company load, caused a decrease in Oregon's allocation factors and the corresponding share of total-company NPC allocated to Oregon compared with the 2014 TAM. This reduction in allocation factors is reflected in the Company's requested rate increase.

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" for which a baseline was set in the 2014 TAM. Other Revenues are expected to increase in 2015 due to an increase in revenue from an ancillary services contract with Seattle City Light for the Stateline wind farm and the South Idaho Exchange with Bonneville Power Administration. On an Oregon-allocated basis, projected Other Revenues are approximately $0.6 million higher in 2015. This increase in Other Revenues partially offsets the increase in NPC, reducing the TAM by approximately $0.6 million.

Q. Have you included the costs and benefits associated with the Energy Imbalance Market (EIM) in the 2015 TAM?

A. No. Due to the uncertainty surrounding the level of benefits that will be achieved, particularly in the early stages of EIM operation, the Company has not included the impact of the EIM in this case. The Company intends to file a separate application with the Commission to address the Company's participation in the EIM, including a proposal to defer the associated costs and benefits.

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 the Generation and Regulatory Initiative Decision Tools (GRID) model. 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. As I discuss below, the Company has updated and refined various inputs to the GRID model in compliance with past Commission orders, including the order in the 2014 TAM, and in an effort to improve the NPC calculation for the 2015 test period.

Q. Is the Company using the same version of the GRID model as used in its 2014 TAM?

A. Yes.

Q. What general inputs were updated for this filing?

A. The Company updated inputs to the GRID model to reflect the information available at the time the Company prepared the NPC study for the current filing. In addition to system load, the Company updated wholesale sales and purchase contracts for electricity, natural gas, and wheeling; wholesale market prices for electricity and natural gas; fuel expenses; transmission capability; characteristics of the Company's generation facilities; and planned outages and forced outages of the Company's generation resources. The historical base period used for outage rates and other inputs relying on four-year historical averages in this filing is the 48-month period ended June 2013.

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. An electronic version of the exhibit is included in the workpapers accompanying the Company's filing, including additional data with more detailed analyses in hourly, daily, monthly, and annual formats by heavy load hours and light load hours.

Q. Please generally describe the changes in NPC compared to the 2014 TAM.

A. Table 1 illustrates the change in total-company NPC by category from the NPC baseline in the 2014 TAM:

Table 1
Net Power Cost Reconciliation

	Total Company ($ millions)	$/MWh
OR TAM CY 2014	**$1,449**	**$24.31**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	$41	
Purchased Power Expense	$13	
Coal Fuel Expense	($4)	
Natural Gas Fuel Expense	$27	
Wheeling, Hydro and Other Expense	$4	
Total Increase/(Decrease) to NPC	**$81**	
OR TAM CY 2015	**$1,530**	**$25.53**

As shown in Table 1, the increase in NPC is driven by a reduction in wholesale sales revenue and increase in natural-gas fuel expense, along with smaller increases in purchased power, wheeling, and other expenses. The increase is partially offset by a reduction in coal fuel expense.

Q. **Does this filing reflect changes in the operation of certain Company-owned thermal resources since the 2014 TAM?**

A. Yes. First, the 2015 TAM includes a full 12 months of operation of the Lake Side 2 natural-gas-fired generating plant (Lake Side 2). The 2014 TAM included Lake Side 2 generation beginning June 2014. Second, the 2015 TAM includes the retirement of one coal-fired generating plant and the conversion of one coal-fired unit to gas-fired operation. The Carbon coal-fired generating plant, located in Utah, will be retired from service April 15, 2015. Unit 3 of the Naughton generating plant, located in Wyoming, is assumed to cease coal-fired operation on

December 31, 2014, and resume operation as a gas-fired unit effective June 1, 2015.

Q. Is it possible that the Company would continue to operate Naughton Unit 3 as a coal-fired facility through the 2015 test period?

A. Yes. To comply with state of Wyoming Regional Haze State Implementation Plan (SIP) requirements, the Company must install selective catalytic reduction (SCR) equipment and a baghouse to reduce emissions of NO_X and PM on Naughton Unit 3 by December 31, 2014. The Company assessed the economics associated with these requirements in a certificate of public convenience and necessity docket before the Wyoming Pubic Service Commission and determined that natural-gas conversion is in the best interests of the Company's customers. In its final action on the Wyoming Regional Haze SIP, the Environmental Protection Agency (EPA) approved the SIP requirements for Naughton Unit 3. The EPA specifically stated its support of the gas conversion of Naughton Unit 3, but noted that because the SIP documentation did not include a gas conversion option, the EPA could not consider that option until the SIP is changed. PacifiCorp is currently working with the State of Wyoming Department of Environmental Quality to amend the permit requiring installation of an SCR and a baghouse at Naughton Unit 3 by December 31, 2014. Once the amended permit is issued, the gas conversion can be delayed until June 30, 2018.

If the allowable timeframe for coal-fired operation is extended beyond December 31, 2014, the Company will update the TAM to reflect the continuation of the unit as a coal-fired base load generation facility and any associated operating restrictions. The Company plans to incorporate the most recent information possible in its NPC update filings throughout the course of this proceeding.

Q. Have you calculated the impact to NPC if Naughton Unit 3 is not converted to gas during the test period and is instead allowed to continue to operate as a coal-fired resource?

A. Yes. The Company prepared a second NPC study for 2015 that incorporates the assumption that coal-fired operations at Naughton Unit 3 continue through the test period. The result is a reduction to total-company NPC of $32.0 million, or approximately $7.8 million on an Oregon-allocated basis. This would result in an overall increase in customer rates of approximately $10.5 million, or 0.9 percent. Because an amended permit has not yet been issued, unless otherwise indicated, the NPC results described in my testimony refer to the scenario that assumes Naughton Unit 3 is converted to gas generation during the test period.

DISCUSSION OF MAJOR COST DRIVERS IN NPC

Q. Please explain the reduction in wholesale sales revenue shown in Table 1.

A. The reduction in wholesale sales revenue is driven by: (1) the expiration of two long-term sales contracts; and (2) reduced volume of wholesale market sales due to a reduction in economic resources. The reduction in sales volumes is partially offset by higher average market prices during 2015.

The 2014 TAM included a long-term sales contract with Shell that expires December 2014. The 2014 TAM also included a legacy sales agreement with Sacramento Municipal Utility District (SMUD) that expires at the end of 2014.

Removing these two contracts reduces wholesale sales revenue by approximately $17.8 million.

Revenue from market transactions (represented in GRID as short-term firm and system balancing sales) is approximately $22.3 million lower than in the 2014 TAM due to a reduction in volume of 1,231 GWh, partially offset by a rise in wholesale market prices. Lower wholesale sales volume is attributed to a reduction in economic thermal resources, mainly related to the loss of low-cost generation from Carbon and Naughton Unit 3 and higher system load. Overall, coal generation is 1,541 GWh lower in the 2015 TAM compared to the 2014 TAM. Forecasted system load in 2015 is 436 GWh higher than the 2014 TAM, reducing the Company's ability to make wholesale sales. Market sales transactions in the 2014 TAM were included at an average price of $33.67/MWh, while market sales in the current case are included at an average price of $35.61/MWh.

Q. Please discuss the increase in natural-gas fuel expense since the 2014 TAM.

A. The increase in natural-gas fuel expense is attributed to Lake Side 2 being included for all 12 months of the test period and the natural-gas-fired operation of Naughton Unit 3 beginning June 2015. In total, these changes increase natural-gas expense by $50.1 million compared to the 2014 TAM. This increase in expense is partially offset by reductions in natural-gas generation volume at other facilities. Total generation from natural-gas facilities increased 539 GWh, and the average cost of natural-gas generation increased from $33.91/MWh to $34.73/MWh in the current case.

Q. Does this case include the natural-gas contracts executed as a result of the Company's 2012 Natural Gas Request for Proposals?

A. Yes. In August 2013, the Company entered into two gas swap transactions as a result of the Company's 2012 Natural Gas Request for Proposals. These contracts were identified in the Company's September 2013 notice of corrections and updates in the 2014 TAM, and were included in the indicative and final updates filed in November 2013.

Q. Why did purchased power expense increase compared to the 2014 TAM?

A. The increase in purchased power expense is driven by higher prices for short-term market purchases and the addition of several new qualifying facilities (QFs), partially offset by a reduction in the portion of the output from the Hermiston plant that is purchased by the Company.

Expenses from market transactions (represented in GRID as short-term firm and system balancing purchases) are approximately $11.9 million higher than in the 2014 TAM, while the volume from such transactions remained relatively steady, decreasing by only 55 GWh (or one percent). Market purchase transactions in the 2014 TAM were included at an average price of $28.30/MWh, while market purchases in the current case are included at an average price of $31.13/MWh.

Total expenses for power purchased from QFs increased by approximately $10.9 million compared to the 2014 TAM. The increase is due to several new renewable QFs, including four large wind QFs and several small solar projects in Utah expected to reach commercial operation in 2015. The increase is partially offset by reduced expenses related to one customer electing to use its QF generation to serve its own load and removal of two QFs that were included in the 2014 TAM but never reached commercial operation.

Q. Did the Company extend any purchased power contracts in its NPC study that are scheduled to expire before the end of 2015?

A. Yes. Several existing QF contracts terminate before the end of the test period, and the Company assumed that these customers will enter contracts to continue selling to the Company at the most recent avoided cost rates. In addition, the Company assumed the existing contract with an industrial customer for operating reserves would be renewed after it expires in December 2014. The Company anticipates updating NPC in this proceeding as more information becomes available.

Q. Please explain the net decrease in coal fuel expense shown in Table 1.

A. Total coal fuel expense is $4.0 million lower than the 2014 TAM due to the aforementioned retirement of Carbon and the conversion of Naughton Unit 3 to natural-gas-fired operation. The reduction in expense due to ceased coal-fired operations at these two facilities is largely offset by increased fuel costs at other plants. Further details supporting the cost of fuel to the Company's remaining coal-fired facilities are provided in the direct testimony of Ms. Crane.

Q. Did the Company include any anticipated changes to plant capacity due to environmental upgrades placed in service through the end of the test period?

A. Yes. The Company's modeling incorporates the following reductions in capacity at three coal-fired generating plants to account for environmental upgrades through the end of the 2015 TAM test period: (1) a 4 MW reduction at Hunter Unit 1 effective July 1, 2014; (2) a 0.5 MW reduction at Hayden Unit effective May 15, 2015; and (3) a 3.5 MW reduction at Jim Bridger Unit 3 effective November 5, 2015.

REFINEMENTS TO THE NPC STUDY SINCE THE 2014 TAM

Q. Has the Company modeled NPC in accordance with the Commission's final order in the 2014 TAM?

A. Yes. The Company's 2015 TAM filing is consistent with Order No. 13-387 in the 2014 TAM, as follows:

- *Wind Shaping*—Consistent with the method adopted in the 2014 TAM, the Company used actual energy output data from its owned and purchased wind facilities to shape hourly wind generation profiles, scaled up or down so when the output within the Company's traditional four-hour blocks is averaged over the course of a month, it is the same as in the long-run median, or P50, forecast. In this case, the Company used 2012 actual output, rather than 2011 output, to shape the normalized forecast. Rolling forward to 2012 output uses the most recent year available at the time the filing was prepared.
- *Bridger Coal Expense*—Expenses for Bridger Coal Company are included based on the operating costs of the mine. Additional details are provided in the testimony of Ms. Crane.
- *Captive Coal Mine Costs*—The Company has excluded management overtime and 50 percent of management annual incentive plan expenses

from the calculation of the cost of coal from affiliate coal mines.

- *Jim Bridger Unit 2 Heat Rate Coefficient*—Rather than use 48 months of actual data, the heat rate for Jim Bridger Unit 2 is based on the actual heat rate for Jim Bridger Unit 1 beginning July 2010 to reflect efficiency improvements from a turbine upgrade.
- *Transition Adjustment*—The Company will calculate the transition adjustments consistent with the 2014 TAM, valuing the freed-up energy using GRID and not including a credit for avoided transmission service from Bonneville Power Administration.

Q. Has the Company refined any inputs to the GRID model to improve the accuracy of its forecast?

A. Yes. The Company included a change to the output of the Leaning Juniper wind plant (Leaning Juniper) associated with a contract unique to that wind project. As a result of the contract, output at Leaning Juniper is forecast at a slightly reduced level, but the Company will receive an offsetting amount of revenue. Both of these components are included in the 2015 TAM.

. The Company also plans to update the 2015 TAM for two changes to network reliability standards recently approved by the Federal Energy Regulatory Commission (FERC). First, BAL-002-WECC-2 modifies contingency reserve requirements, effective October 1, 2014. The current contingency reserve requirement is for the sum of five percent of load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation. Wind and solar are treated the same as hydro. The newly approved contingency reserve requirement is for the sum of three percent of hourly integrated load plus three percent of hourly integrated generation. Second, BAL-003-1 includes requirements pertaining to the provision of reserves for frequency response effective April 1, 2015. The Company is evaluating the impact of each of these standards and developing the required inputs to incorporate the modified reserve requirements in GRID. The Company anticipates including the updated reserve calculation in its rebuttal filing.

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 Order No. 09-432?

A. Yes. The Company has complied with the TAM Guidelines applicable to the initial filing in a stand-alone TAM. As previously discussed, the Company proposes to update the 2015 TAM to reflect a change in the operation of Naughton Unit 3 if continued coal-fired generation is allowed during 2015.

Q. Did the Company make changes to the GRID model 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. Has the Company provided information regarding its anticipated TAM updates?

A. Yes. Exhibit PAC/104 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 ___
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 2014

PacifiCorp
CY 2015 TAM

	ACCT.	Total Company: UE-264 Final TAM CY 2014	Total Company: TAM CY 2015	Factor	Factors CY 2014	Factors CY 2015	Oregon Allocated: UE-264 Final TAM CY 2014	Oregon Allocated: TAM CY 2015
Sales for Resale								
Existing Firm PPL	447	26,770,321	13,961,671	SG	26.053%	25.687%	6,974,472	3,586,366
Existing Firm UPL	447	30,332,094	29,139,801	SG	26.053%	25.687%	7,902,421	7,485,207
Post-Merger Firm	447	392,665,570	365,630,296	SG	26.053%	25.687%	102,301,167	93,920,287
Non-Firm	447	-	-	SE	24.687%	24.484%	-	-
Total Sales for Resale		449,767,986	408,731,768				117,178,061	104,991,860
Purchased Power								
Existing Firm Demand PPL	555	2,867,295	3,292,634	SG	26.053%	25.687%	747,016	845,787
Existing Firm Demand UPL	555	52,532,746	55,379,617	SG	26.053%	25.687%	13,686,357	14,225,488
Existing Firm Energy	555	25,971,161	29,154,344	SE	24.687%	24.484%	6,411,431	7,138,141
Post-merger Firm	555	519,804,990	526,772,591	SG	26.053%	25.687%	135,424,802	135,313,275
Secondary Purchases	555	-	-	SE	24.687%	24.484%	-	-
Other Generation Expense	555	3,344,256	3,515,487	SG	26.053%	25.687%	871,279	903,031
Total Purchased Power		604,520,448	618,114,674				157,140,886	158,425,722
Wheeling Expense								
Existing Firm PPL	565	27,297,335	27,165,030	SG	26.053%	25.687%	7,111,775	6,977,943
Existing Firm UPL	565	-	-	SG	26.053%	25.687%	-	-
Post-merger Firm	565	110,997,010	112,112,433	SG	26.053%	25.687%	28,918,053	28,798,576
Non-Firm	565	5,066,934	6,899,428	SE	24.687%	24.484%	1,250,860	1,689,254
Total Wheeling Expense		143,361,280	146,176,891				37,280,689	37,465,773
Fuel Expense								
Fuel Consumed - Coal	501	744,132,904	733,921,363	SE	24.687%	24.484%	183,702,102	179,693,090
Fuel Consumed - Coal (Cholla)	501	55,644,930	61,820,042	SE	24.687%	24.484%	13,736,915	15,136,001
Fuel Consumed - Gas	501	4,104,921	4,798,513	SE	24.687%	24.484%	1,013,371	1,174,866
Natural Gas Consumed	547	336,503,960	363,638,686	SE	24.687%	24.484%	83,071,834	89,033,188
Simple Cycle Comb. Turbines	547	6,699,935	5,991,022	SE	24.687%	24.484%	1,653,995	1,466,840
Steam from Other Sources	503	3,441,624	4,106,159	SE	24.687%	24.484%	849,624	1,005,351
Total Fuel Expense		1,150,528,274	1,174,275,784				284,027,841	287,509,336
Net Power Costs (Per GRID)		1,448,642,016	1,529,835,581				361,271,356	378,408,972
Oregon Situs Solar Project Benefit		(131,319)	(154,164)	OR	100.000%	100.000%	(131,319)	(154,164)
Total Net of Adjustments		1,448,510,698	1,529,681,417				361,140,037	378,254,808
Increase Absent Load Change								17,114,771
Oregon-allocated NPC Baseline in Rates from UE-264							$361,140,037	
$ Change due to load variance from UE-264 forecast							(1,852,305)	
2015 Recovery of NPC in Rates							$359,287,732	
Increase Including Load Change								**18,967,076**
Add Other Revenue Change								(642,976)
Total TAM Increase								**18,324,099**

Docket No. UE ___
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 2014

PacifiCorp

OR TAM 2015 NPC

Net Power Cost Analysis

$

12 months ending December 2015	01/15-12/15	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Special Sales For Resale													
Long Term Firm Sales													
Black Hills s27013/s28160	13,961,670	1,172,416	1,119,070	1,185,767	1,145,501	1,173,236	1,151,796	1,176,884	1,169,735	1,162,394	1,174,130	1,149,347	1,181,394
BPA Wind s42818	2,633,762	298,403	267,250	297,745	186,990	191,247	181,087	112,516	113,088	159,620	199,177	278,458	348,181
Hurricane Sale s393046	13,751	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
LADWP (IPP Layoff)	29,139,801	2,402,996	2,058,084	2,080,694	1,645,803	2,403,743	2,692,677	2,830,751	2,828,315	2,013,576	3,397,116	2,281,743	2,504,305
Leaning Juniper Revenue	120,727	7,467	7,861	12,327	6,824	8,738	9,185	13,516	14,132	12,523	11,070	8,345	8,739
UMPA II s45631	9,599,124	593,283	561,909	593,283	582,825	593,283	932,517	1,779,848	1,400,150	792,640	593,283	582,825	593,283
Total Long Term Firm Sales	55,468,836	4,475,711	4,015,321	4,170,962	3,569,088	4,371,392	4,968,407	5,914,660	5,526,567	4,141,898	5,375,921	4,301,864	4,637,046
Short Term Firm Sales													
Palo Verde	894,440	310,780	272,880	310,780	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	894,440	310,780	272,880	310,780	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	63,851,530	7,859,245	5,731,113	6,398,103	3,106,598	1,112,151	663,590	5,486,451	6,424,790	6,544,275	5,768,924	7,484,760	7,271,533
Four Corners	89,141,474	8,541,652	7,431,203	5,439,192	6,570,907	5,347,222	5,330,239	8,282,583	11,311,379	8,242,035	6,312,618	8,987,987	7,344,458
Mead	44,730,741	4,179,051	3,855,967	3,537,624	2,839,294	3,400,979	2,445,512	4,208,704	4,735,150	3,960,456	4,101,503	3,854,187	3,612,315
Mid Columbia	14,219,804	740,742	998,183	1,521,367	18,826	9,251	82,908	824,690	1,748,714	2,866,144	2,926,591	1,686,692	795,696
Mona	20,806,405	1,008,359	367,319	388,336	1,546,917	2,023,519	2,038,709	2,818,481	3,057,464	3,793,126	1,942,502	817,092	1,004,583
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	119,616,225	10,859,716	10,326,269	9,301,732	8,880,372	9,760,212	9,700,610	11,879,793	9,330,589	8,872,800	10,218,306	10,387,137	10,098,689
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Trapped Energy	2,313	-	336	-	799	57	-	-	-	575	546	-	-
Total System Balancing Sales	352,368,492	33,188,765	28,710,390	26,586,353	22,963,713	21,653,390	20,261,567	33,500,700	36,608,086	34,279,411	31,270,989	33,217,855	30,127,274
Total Special Sales For Resale	408,731,768	37,975,255	32,998,590	31,068,094	26,532,801	26,024,783	25,229,974	39,415,361	42,134,652	38,421,309	36,646,910	37,519,718	34,764,320

PacifiCorp

OR TAM 2015 NPC

Net Power Cost Analysis

12 months ending December 2015	01/15-12/15	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental p27875	856,309	56,121	270,449	-	106,524	150,345	-	-	-	-	34,052	123,768	115,050
Combine Hills Wind p160595	5,184,876	496,898	323,085	574,537	403,458	375,039	451,979	433,241	429,645	409,479	439,678	490,452	357,384
Deseret Purchase p194277	35,867,980	3,083,965	2,951,197	3,083,965	3,032,333	2,558,418	2,742,824	3,083,965	3,083,965	3,039,709	3,083,965	3,039,709	3,083,965
Douglas PUD Settlement p38185	2,055,576	98,518	89,713	144,774	254,273	325,677	352,433	257,843	179,186	87,568	78,044	81,282	106,263
Gemstate p99489	3,211,600	263,700	260,500	265,400	260,500	260,500	260,500	260,500	279,400	260,500	282,900	293,500	263,700
Georgia-Pacific Camas	6,501,763	552,204	498,766	552,204	534,392	552,204	534,392	552,204	552,204	534,392	552,204	534,392	552,204
Hermiston Purchase p99563	79,391,905	7,844,212	7,162,650	6,027,109	4,765,954	3,824,893	4,385,746	7,155,402	7,859,013	7,405,821	7,816,713	7,323,052	7,821,340
Hurricane Purchase p393045	125,120	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427	10,427
IPP Purchase	29,139,801	2,402,996	2,058,084	2,080,694	1,645,803	2,403,743	2,692,677	2,830,751	2,828,315	2,013,576	3,397,116	2,281,743	2,504,305
MagCorp Reserves p510378	6,355,850	533,330	581,450	545,360	469,170	461,150	477,190	533,330	537,340	545,360	569,420	549,370	553,380
Nucor p346856	6,018,000	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500	501,500
P4 Production p137215/p145258	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
PGE Cove p83984	323,118	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927	26,927
Rock River Wind p100371	4,940,852	602,477	475,464	480,834	376,185	360,263	271,745	193,726	234,387	304,450	436,506	593,879	610,936
Small Purchases east	56,350	5,310	5,186	6,277	4,722	3,887	3,884	3,623	3,956	5,488	4,433	4,476	5,107
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind p460457	20,598,497	2,305,957	1,595,827	2,351,682	1,690,904	1,714,597	1,181,550	1,054,248	1,080,038	1,423,019	1,787,221	2,006,943	2,406,511
Top of the World Wind p522807	40,244,926	5,293,915	3,991,015	3,804,703	3,095,178	2,664,502	2,418,363	1,930,210	2,086,321	2,260,849	2,895,794	4,238,572	5,565,507
Tri-State Purchase p27057	10,417,371	922,911	854,296	807,547	770,766	817,365	858,148	936,165	935,183	902,330	917,020	877,785	817,856
Wolverine Creek Wind p244520	10,256,405	760,815	599,185	1,196,907	1,150,456	1,120,408	872,763	852,864	799,983	744,483	643,953	843,433	671,156
Long Term Firm Purchases Total	281,546,298	27,428,850	23,922,389	24,127,512	20,766,138	19,798,511	19,709,713	22,283,592	23,094,455	22,142,542	25,144,537	25,487,875	27,640,184
Seasonal Purchased Power													
Constellation 2013-2016	6,068,600	-	-	-	-	-	-	2,158,416	2,121,184	1,789,000	-	-	-
Seasonal Purchased Power Total	6,068,600	-	-	-	-	-	-	2,158,416	2,121,184	1,789,000	-	-	-

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12 months ending December 2015	01/15-12/15	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Qualifying Facilities													
QF California	6,902,169	637,342	714,280	794,400	1,013,509	1,028,382	797,732	379,511	282,458	261,797	263,905	292,373	436,479
QF Idaho	8,545,790	611,664	557,257	689,422	752,035	911,295	1,002,105	759,176	623,073	635,084	685,849	677,916	640,916
QF Oregon	27,437,190	2,284,419	2,144,052	2,453,355	2,798,328	2,888,377	2,584,588	2,218,163	2,086,992	2,142,692	1,949,187	1,736,818	2,150,219
QF Utah	5,254,276	126,215	146,009	173,780	186,556	281,386	432,138	406,781	751,356	710,386	728,840	686,975	623,853
QF Washington	627,025	31,328	31,324	31,290	35,658	51,401	72,623	88,902	93,412	80,707	47,670	31,385	31,328
QF Wyoming	760,108	22,889	21,559	20,863	49,065	89,336	89,967	116,599	116,514	105,605	59,394	34,124	34,193
Biomass One QF	14,187,605	1,302,686	1,190,159	1,319,319	718,405	723,393	718,402	1,404,148	1,404,217	1,395,239	1,425,312	1,341,046	1,245,279
Champlin Blue Mtn Wind QF	1,612,152	-	-	-	-	-	-	-	-	-	-	47,243	1,564,910
Chevron Wind p499335 QF	2,439,897	220,458	199,832	196,164	78,193	89,146	172,426	153,292	243,792	205,029	307,113	324,394	250,058
DCFP p316701 QF	153,092	12,362	9,535	10,916	10,907	20,324	18,943	10,178	5,422	11,770	20,203	16,729	5,804
Evergreen BioPower p351030 QF	2,478,138	194,715	189,958	176,523	141,532	157,092	168,446	194,211	269,823	256,445	306,267	211,156	211,968
ExxonMobil p255042 QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	7,452,821	671,391	572,575	680,769	532,192	533,286	435,110	544,635	643,933	546,835	661,873	724,901	905,322
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	4,764,355	-	-	-	-	735,564	616,578	557,900	453,103	488,178	673,102	597,668	642,263
Long Ridge Wind I QF	44,112	-	-	-	-	-	-	-	-	-	-	-	44,112
Long Ridge Wind II QF	44,112	-	-	-	-	-	-	-	-	-	-	-	44,112
Mountain Wind 1 p367721 QF	8,485,221	1,204,831	771,242	797,935	584,542	493,472	364,985	403,538	539,866	644,506	724,873	831,109	1,124,321
Mountain Wind 2 p398449 QF	12,284,280	1,758,851	1,078,685	1,124,962	797,084	859,408	702,966	794,867	839,387	813,454	861,128	1,116,705	1,536,783
North Point Wind QF	16,299,568	1,454,189	1,243,197	1,472,266	1,168,023	1,156,823	962,878	1,213,856	1,429,690	1,214,962	1,456,640	1,567,358	1,959,686
Oregon Wind Farm QF	11,798,090	691,263	738,788	952,230	1,170,368	1,187,991	1,389,764	1,420,408	1,070,425	881,619	901,747	1,036,952	356,535
Power County North Wind QF p5756	4,124,755	379,580	383,534	351,063	330,930	266,151	237,420	296,505	270,575	307,628	402,527	388,503	510,340
Power County South Wind QF p5756	3,943,700	410,977	368,187	379,161	298,713	235,677	235,457	222,141	230,438	274,775	344,969	403,347	539,857
Roseburg Dillard QF	1,065,195	134,050	134,834	66,560	45,762	25,361	32,675	142,165	126,948	110,133	35,941	86,074	124,692
SF Phosphates	-	-	-	-	-	-	-	-	-	-	-	-	-
Spanish Fork Wind 2 p311681 QF	2,844,147	183,965	199,368	175,977	166,978	170,414	248,216	297,076	351,514	285,067	231,636	255,544	278,391
Sunnyside p83997/p59965 QF	27,794,859	2,451,869	2,344,758	2,454,297	1,629,359	2,205,904	2,405,857	2,482,305	2,410,580	2,396,768	2,087,195	2,427,954	2,498,014
Tesoro QF	1,245,907	114,108	102,529	137,336	112,604	84,580	73,956	94,579	88,406	94,416	106,915	99,265	137,215
Threemile Canyon Wind QF p50013	2,087,775	152,303	159,689	178,983	167,021	212,401	199,278	177,403	174,888	165,712	193,399	149,917	156,781
US Magnesium QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Qualifying Facilities Total	174,676,338	15,051,453	13,301,352	14,637,572	12,787,764	14,407,164	13,962,510	14,378,337	14,506,810	14,028,807	14,475,684	15,085,456	18,053,429
Mid-Columbia Contracts													
Douglas - Wells p60828	3,637,620	301,420	301,420	301,420	301,420	301,420	301,420	301,420	301,420	306,564	306,564	306,564	306,564
Grant Reasonable	(5,991,604)	(499,300)	(499,300)	(499,300)	(499,300)	(499,300)	(499,300)	(499,300)	(499,300)	(499,300)	(499,300)	(499,300)	(499,300)
Grant Surplus p258951	2,046,082	170,507	170,507	170,507	170,507	170,507	170,507	170,507	170,507	170,507	170,507	170,507	170,507
Mid-Columbia Contracts Total	(307,901)	(27,373)	(27,373)	(27,373)	(27,373)	(27,373)	(27,373)	(27,373)	(27,373)	(22,229)	(22,229)	(22,229)	(22,229)
Total Long Term Firm Purchases	461,983,335	42,452,930	37,196,368	38,737,711	33,526,529	34,178,302	33,644,850	38,792,972	39,695,076	37,938,120	39,597,992	40,551,102	45,671,383

PacifiCorp

OR TAM 2015 NPC

Net Power Cost Analysis

12 months ending December 2015	01/15-12/15	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Storage & Exchange													
APS Exchange p58118/s58119	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind p63507	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind p79207	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho p64885/p83975/p647	(42)	-	-	-	-	-	-	(42)	-	-	-	-	-
Cowlitz Swift p65787	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I p63508/p63510	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange p340325	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
PSCO FC III p63362/s63361	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange p66276	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line p105228	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	5,399,958	450,000	450,000	450,000	450,000	450,000	450,000	449,958	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
Mid Columbia	1,005,360	349,320	306,720	349,320	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	1,005,360	349,320	306,720	349,320	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	8,293,205	97,208	34,095	64,068	670,591	2,460,362	2,926,650	775,582	246,660	310,231	284,837	151,948	270,972
Four Corners	7,320,088	233,227	177,310	1,070,471	176,568	31,927	302,390	951,022	819,774	988,561	1,155,998	759,932	652,907
Mead	32,350	3,022	1,095	1,563	1,028	461	396	3,804	-	7,711	450	2,542	10,279
Mid Columbia	93,882,442	1,628,345	2,171,342	4,976,832	13,199,749	16,212,971	15,398,666	19,046,976	16,827,304	995,435	2,158,744	453,048	813,029
Mona	36,580,762	3,988,151	5,927,254	7,047,452	2,560,061	2,277,666	1,219,239	679,208	1,098,402	810,949	3,035,207	4,594,226	3,342,947
NOB	101,685	-	-	-	8,343	22,026	32,735	38,580	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
Emergency Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Total System Balancing Purchases	146,210,533	5,949,953	8,311,097	13,160,387	16,616,340	21,005,414	19,880,077	21,495,173	18,992,141	3,112,887	6,635,236	5,961,696	5,090,134
Total Purchased Power & Net Inte	614,599,186	49,202,203	46,264,184	52,697,418	50,592,869	55,633,716	53,974,927	60,738,103	59,137,216	41,501,007	46,683,228	46,962,798	51,211,518

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Net Power Cost Analysis

12 months ending December 2015	01/15-12/15	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Wheeling & U. of F. Expense													
Firm Wheeling	146,137,031	12,434,123	11,978,101	12,001,307	11,850,132	11,683,614	12,479,111	13,078,991	12,709,466	11,705,595	11,703,899	12,139,548	12,373,145
ST Firm & Non-Firm	39,860	8,223	5,919	1,938	1,276	5,286	2,059	1,000	957	2,587	1,827	1,535	7,253
Total Wheeling & U. of F. Expense	146,176,891	12,442,346	11,984,020	12,003,245	11,851,408	11,688,899	12,481,170	13,079,991	12,710,423	11,708,182	11,705,726	12,141,083	12,380,398
Coal Fuel Burn Expense													
Carbon	7,359,409	2,137,237	2,024,530	2,249,101	952,683	(560)	(630)	(447)	(500)	(502)	(385)	(453)	(666)
Cholla	61,820,042	5,588,502	5,203,376	5,617,886	3,441,911	4,521,247	4,382,269	5,160,655	5,883,131	5,507,740	5,498,096	5,358,807	5,656,420
Colstrip	16,049,189	1,436,955	1,297,276	1,436,713	1,390,655	880,422	1,080,045	1,437,115	1,436,284	1,390,964	1,436,401	1,389,738	1,436,621
Craig	25,020,339	2,234,130	2,016,833	2,233,454	2,161,236	2,231,711	2,156,529	2,234,098	2,231,144	2,159,803	1,730,677	1,397,909	2,232,814
Dave Johnston	62,862,559	5,315,449	4,727,019	3,967,051	5,337,126	5,436,305	5,379,608	5,700,495	5,695,857	5,460,851	5,539,120	5,237,719	5,065,959
Hayden	13,859,273	1,273,584	1,225,753	1,350,255	908,972	598,623	928,344	1,209,956	1,256,199	1,139,687	1,345,308	1,338,402	1,284,189
Hunter	164,989,491	14,772,063	13,206,722	10,083,401	13,032,772	13,326,029	13,114,309	14,769,762	14,944,051	14,200,237	14,465,737	14,321,029	14,753,379
Huntington	123,718,548	11,242,262	10,157,399	11,264,448	10,319,369	10,253,175	9,906,448	11,198,878	11,339,958	9,492,385	8,428,874	9,027,989	11,087,362
Jim Bridger	220,910,304	18,948,063	17,045,760	17,189,218	15,726,190	14,822,095	16,967,510	20,596,236	20,666,713	19,367,022	20,398,142	19,273,033	19,910,323
Naughton	71,354,607	6,401,618	5,780,522	6,377,568	4,446,898	4,864,840	5,535,793	6,403,951	6,394,236	6,196,913	6,377,775	6,192,698	6,381,796
Wyodak	27,797,644	2,483,406	2,222,260	2,401,772	1,435,428	2,398,078	2,351,480	2,432,755	2,430,060	2,351,352	2,432,014	2,401,780	2,457,260
Total Coal Fuel Burn Expense	795,741,405	71,833,270	64,907,453	64,170,866	59,153,238	59,331,966	61,801,706	71,143,454	72,277,135	67,266,450	67,651,758	65,938,651	70,265,458
Gas Fuel Burn Expense													
Chehalis	40,745,984	1,372,857	-	-	-	-	-	6,907,932	7,600,863	7,275,036	8,642,590	4,533,451	4,413,256
Currant Creek	58,804,374	4,395,055	4,314,297	5,357,394	4,313,785	3,528,162	3,666,844	6,306,455	6,647,060	6,034,258	3,193,293	5,620,923	5,426,848
Gadsby	4,499,991	-	-	-	-	-	-	1,528,276	2,167,489	804,226	-	-	-
Gadsby CT	5,085,127	186,174	236,002	177,053	222,719	176,423	355,703	642,618	835,089	679,976	691,160	494,244	387,967
Hermiston	35,290,406	4,148,649	3,510,053	2,373,449	1,147,829	222,065	778,267	3,462,786	4,147,587	3,716,692	4,106,037	3,598,969	4,078,023
Lake Side 1	84,599,021	8,069,186	7,085,399	6,753,064	5,734,730	5,331,059	6,564,011	8,267,618	8,636,192	8,114,277	4,588,626	7,812,545	7,642,314
Lake Side 2	88,669,032	8,715,829	7,853,018	7,136,536	4,198,254	6,494,867	7,089,118	7,691,562	8,299,131	7,869,736	7,659,334	7,547,444	8,114,201
Naughton - Gas	10,233,420	-	-	-	-	-	-	3,091,218	4,346,231	2,795,971	-	-	-
Total Gas Fuel Burn	327,927,356	26,887,750	22,998,769	21,797,496	15,617,317	15,752,577	18,453,943	37,898,464	42,679,642	37,290,173	28,881,039	29,607,576	30,062,609
Gas Physical	(66,375)	(22,863)	(20,650)	(22,863)	-	-	-	-	-	-	-	-	-
Gas Swaps	8,543,303	103,928	164,430	299,228	926,850	996,805	931,050	1,145,295	1,111,815	1,092,150	857,925	596,310	317,518
Clay Basin Gas Storage	302,193	(32,194)	(20,421)	(2,763)	50,533	50,533	50,533	50,533	50,533	50,533	50,533	23,331	(19,491)
Pipeline Reservation Fees	37,721,744	3,045,438	2,908,486	3,045,438	2,981,673	3,030,053	3,055,826	3,479,657	3,479,657	3,431,277	3,104,206	3,055,826	3,104,206
Total Gas Fuel Burn Expense	374,428,221	29,982,059	26,030,613	25,116,537	19,576,372	19,829,968	22,491,352	42,573,950	47,321,647	41,864,133	32,893,704	33,283,043	33,464,843
Other Generation													
Blundell	4,106,159	375,239	338,919	375,239	340,684	216,481	331,059	342,081	342,178	341,738	364,203	363,150	375,186
Integration Charge	3,515,487	338,097	277,333	320,883	273,128	282,736	272,879	264,073	269,293	260,279	289,457	319,171	348,160
Total Other Generation	7,621,646	713,336	616,251	696,122	613,812	499,217	603,938	606,154	611,471	602,017	653,660	682,321	723,346
Net Power Cost	**1,529,835,581**	126,197,959	116,803,932	123,616,094	115,254,898	120,958,983	126,123,118	148,726,291	149,923,241	124,520,479	122,941,167	121,488,178	133,281,241
Net Power Cost/Net System Load	**25.53**	**23.66**	**24.69**	**25.23**	**24.96**	**25.27**	**25.87**	**27.10**	**27.75**	**26.17**	**25.70**	**24.71**	**24.99**

Docket No. UE ___
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 2014

PacifiCorp
Oregon - CY 2015 TAM
Other Revenues - Stand Alone TAM Adjustment

	Total Company					Oregon Allocated	
	UE-264	CY 2015	Factor	Factors CY 2014	Factors CY 2015	UE-264	CY 2015
Seattle City Light - Stateline Wind Farm	(7,377,376)	(10,205,770)	SG	26.053%	25.687%	(1,922,028)	(2,621,579)
Non-company owned Foote Creek	(2,454,093)	(1,106,372)	SG	26.053%	25.687%	(639,365)	(284,196)
BPA South Idaho Exchange	(7,645,512)	(9,240,627)	SG	26.053%	25.687%	(1,991,885)	(2,373,661)
Little Mountain Steam Revenues	-	-	SG	26.053%	25.687%	-	-
James River Royalty Offset	(4,302,805)	(3,926,947)	SG	26.053%	25.687%	(1,121,010)	(1,008,724)
Total Other Revenue	(21,779,786)	(24,479,716)				(5,674,288)	(6,288,160)

Decrease (Increase) in Other Revenues Absent Load Change		(613,873)
Baseline Other Revenues in Rates	(5,674,288)	
$ Change due to load variance from UE 264 CY 2014 forecast	29,104	
Other Revenues in Rates using 2015 load forecast	(5,645,184)	
Decrease (Increase) in Other Revenues Including Load Change		**(642,976)**

Docket No. UE ___
Exhibit PAC/104
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 2014

List of Known Items Expected to be Updated During the 2015 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. Potential new qualifying facility purchase contracts with Bevan Solar, BPA Foote Creek II, Chopin Wind, City of Astoria, Enterprise Solar, Escalante Solar I, Escalante Solar II, Granite Mountain East, Granite Mountain West, Iron Springs Solar, Milford II, Pavant Solar, Pioneer Wind Park, PSCO Foote Creek III, Redmond Minerals, Surprise Valley Electric Coop, Warm Springs Hydro.
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.

Other

19. Changes to reserve requirements related to network reliability standards BAL-002-WECC-2, effective October 1, 2014, and BAL-003-1, effective April 1, 2015.
20. Potential extension of coal-fired operation at Naughton Unit 3 pending approval of a revised permit from the State of Wyoming Department of Environmental Quality.

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 Contracts		Escalating Contracts		Transportation Contacts	
Plant	Supplier/Mine	Volume	Price	Volume	Price	Volume	Price	Volume	Price
Bridger	Bridger Coal Company	√							
	Black Butte					√	√		
	Union Pacific Railway							√	√
Carbon	Deer Creek	√							
	Utah American Energy - West Ridge			√	√				
	Rhino Energy - Castle Valley			√	√				
	Utah Trucking							√	√
Cholla	Peabody Coalsales - Lee Ranch Mine					√	√		
	BNSF Railway							√	√
Colstrip	Westmoreland - Rosebud Mine					√	√	√	√
Craig	Trapper Mine	√							
	Rio Tinto- - Colowyo Mine						√		
	Union Pacific Railway								√
Hayden	Twentymile Mine					√	√		
	Union Pacific							√	√
Hunter	Deer Creek	√							
	Arch - Sufco			√	√				
	Utah American Energy - West Ridge			√	√				
	Utah Trucking							√	√
Huntington	Deer Creek	√							
	Arch - Sufco			√	√				
	Rhino Energy - Castle Valley			√	√				
	Utah Trucking							√	√
D Johnston	Open Position					√	√		
	Western Fuels - Dry Fork Mine								
	BNSF Railway							√	√
Naughton	Chevron Mining - Kemmerer Mine					√	√		
Wyodak	Black Hills - Wyodak Mine					√	√		

REDACTED
Docket No. UE ___
Exhibit PAC/200
Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Cindy A. Crane

April 2014

DIRECT TESTIMONY OF CINDY A. CRANE

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/201— PacifiCorp Compliance Proposal for Periodic Fuel Supply Plans for PacifiCorp’s Affiliate Mines

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

A. My name is Cindy A. Crane. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. My position is Vice President, Interwest Mining Company and Fuel Resources for PacifiCorp Energy.

QUALIFICATIONS

Q. Briefly describe your professional experience.

A. I joined PacifiCorp in 1990 and have held positions of increasing responsibility, including Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis, and Vice President of Strategy and Division Services. My responsibilities have included the management and development of PacifiCorp's 10-year business plan, assessing individual business strategies for PacifiCorp Energy, managing the construction of the Company's Wyoming wind plants, and assessing the feasibility of a nuclear power plant. In March 2009, I was appointed to my present position as Vice President of Interwest Mining Company and Fuel Resources. In this position, I am responsible for the operations of Energy West Mining Company and Bridger Coal Company, as well as overall coal supply acquisition and fuel management for PacifiCorp's coal-fired generating plants.

PURPOSE AND SUMMARY

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

A. I explain the Company's overall approach to providing the coal supply for the

Company's coal-fired generating plants and support for the level of coal prices included in coal fuel expense in this case.

Q. Please summarize your testimony.

A. My testimony:

- Presents the Company's proposed approach to developing periodic fuel supply plans directed by Order No. 13-387 in docket UE 264, the Company's 2014 Transition Adjustment Mechanism (TAM);[1]
- Explains the primary causes of changes to the total-company coal fuel expense reflected in the 2015 TAM;
- Provides background on third-party coal contracts and current contract price re-openers; and
- Reviews the Company's affiliate mine coal prices and compares them to other supply alternatives.

OVERVIEW OF THE COMPANY'S COAL SUPPLIES

Q. How does the Company plan to meet fuel supplies for its coal plants in 2015?

A. As reflected below in confidential Table 1, the Company employs a diversified coal supply strategy. The Company will supply approximately 62.3 percent of its 2015 coal requirements with third-party coal supplies and 37.7 percent with coal from the Company's affiliate mines. More specifically: (1) approximately 24.8 percent of the Company's total coal requirement will be supplied under fixed-price contracts; (2) approximately 28.7 percent will be supplied under contracts that escalate or de-escalate based on changes to producer and consumer

[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 7 (Oct. 28, 2013) (2014 TAM).

price indices; (3) approximately 8.5 percent of the total coal requirement will be supplied to the Dave Johnston plant from currently unidentified Powder River Basin mines; and (4) approximately 0.3 percent represents the consumption of Carbon plant inventory before its closure in April 2015.

Table 1: Coal Sourcing

[redacted]

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

A. The Utah plants are sourced collectively through a diversified portfolio of coal supplies. While the Deer Creek mine supplies primarily the Huntington plant and a portion of the Hunter plant, the contract coal supplies are typically interchangeable between the plants. Interchangeable coal supplies allow the Company to minimize transportation costs between the coal mines and generating plants while ensuring that the coal quality blend meets the quality specifications for each plant.

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 3.7 million tons in 2015; the Company currently has 1.5 million tons of coal for the plant under contract. The Company intends to solicit multi-year coal supplies from Powder River Basin mines through a request for proposal during the second quarter of 2014.

PERIODIC FUEL SUPPLY PLANS

Q. In the final order in the Company's 2014 TAM, the Commission stated that the Company must prepare periodic fuel supply plans. Is the Company in the process of developing the required plans?

A. Yes. The company is currently working on developing periodic fuel supply plans for the Jim Bridger generating plant and the Hunter and Huntington plants that compare "affiliate mine fuel supply to other alternative fuel supply options, including market alternatives, to facilitate implementing prudence and affiliate transaction standards in future proceedings[,]" as ordered in Order No. 13-387.[2]

Q. What is the status of the Company's periodic fuel supply plans?

A. The Company developed an outline of its periodic fuel supply plans, which is

[2] Order No. 13-387 at 7.

attached to my testimony as Exhibit PAC/201. The Company plans to file its periodic fuel plans in 2015.

COAL COST CHANGES

Q. Has coal fuel expense in the 2015 TAM changed from levels reflected in the Company's 2014 TAM?

A. Yes. As mentioned in the testimony of Mr. Brian S. Dickman, coal fuel expense has decreased by $4.1 million on a total-company basis, decreasing from $799.8 million in the 2014 TAM update to $795.7 million in the 2015 TAM. This decrease represents an increase related to higher coal prices of approximately $35.4 million, offset by a decrease relating to reduced coal-fired generation of approximately $39.5 million.

Q. What are the primary drivers of the $35.4 million increase in coal prices?

A. Approximately $15.5 million of the increase in coal prices is associated with third-party coal purchases and transportation costs, $19.4 million is associated with the Company's affiliated mines, and $0.5 million is associated with increased operating costs at the Hunter prep plant.

THIRD-PARTY COAL CONTRACTS

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

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

Table 2: Coal and Transportation Contract Price Changes

[redacted]

Coal Supply Agreements for the Wyoming Plants

Naughton

Q. Please describe the coal supply arrangement for the Naughton plant.

A. The Naughton plant is supplied by an overland conveyor by Westmoreland's adjacent Kemmerer mine under a long-term coal supply agreement through 2021. The Kemmerer mine has supplied the Naughton plant with coal for more than 50 years. Westmoreland acquired the Kemmerer mine from Chevron Mining in January 2012.

The current coal supply agreement was renegotiated in September 2010 and includes a contract minimum of [redacted] tons. The contract allows for contract escalation and de-escalation of the new contract price based on quarterly changes in contract-specific producer and consumer price indices, as well as production taxes and royalties through 2015.

Q. How do coal prices for the Naughton plant compare to the 2014 TAM?

A. As reflected in confidential Table 3 below, coal fuel expense at the Naughton generating plant increases from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM, an increase of [redacted] per ton or [redacted] total. Approximately [redacted] of the increase is associated with the discontinuation of coal-fired operations at Naughton Unit 3 at the end of 2014; the remaining increase of [redacted] is associated with contract price escalation.

Table 3: Naughton Contract Tonnage

[redacted]

Q. Please explain the coal fuel expense increase related to the discontinuation of coal-fired operations at Naughton Unit 3.

A. If Naughton Unit 3 stops coal-fired operations at the end of 2014, the amount of coal consumed at the Naughton plant will decrease, and the Company will incur [redacted].

As reflected in confidential Table 3 above, the Naughton coal supply agreement includes two pricing tiers. The first tier is applied to the first [redacted] tons delivered in each contract year, which is the contract minimum. The second tier is applied to volumes between [redacted] and [redacted] tons each year. Assuming discontinuation of Naughton Unit 3 as a coal-fired generating unit at the end of 2014, the Naughton plant will consume approximately [redacted] Tier 1 tons in 2015 and, [redacted]. Comparatively, in the 2014 TAM, the Naughton plant burned [redacted] tons of Tier 1 coal, [redacted] tons of Tier 2 coal and [redacted] tons of Haystack coal. [redacted].

Q. How much of the increase related to the discontinuation of coal-fired operations at Naughton Unit 3 is attributable to [redacted]?

A. As reflected in confidential Table 3 above, almost [redacted].

Wyodak

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

A. As I previously testified in the 2014 TAM**,** the Wyodak plant is supplied under a long-term coal supply agreement with Wyodak Resources Development Company (Wyodak Resources). This agreement provides for two contract price re-openers—July 1, 2014, and July 1, 2019. The 2015 TAM reflects a full-year impact of the July 2014 contract re-opener, compared to the half-year impact reflected in the 2014 TAM.

Q. Please explain how the Wyodak coal price is reset under the July 1, 2014 price re-opener.

A. The agreement provides for the purchase coal price to be set at a level equal to the sum of the spot price of Powder River Basin 8400 Btu coal, average rail transportation costs from the two closest Powder River Basin mines to the Wyodak plant in railroad-supplied railcars, and a levelized fixed charge associated with construction of a hypothetical rail unloading facility amortized on a straight-line basis over 20 years.

Q. What is the current status of negotiations with Wyodak Resources?

A. The Company and Wyodak Resources reached agreement on the third price component—the capital costs associated with construction of a hypothetical rail unloading facility. But the parties continue to negotiate the first and second contract price components—the spot price of Powder River Basin 8400 Btu coal and average rail transportation costs.

Q. What capital costs did the Company and Wyodak Resources agree to use in determining a levelized fixed charge for the third price component?

A. The Company and Wyodak Resources agreed to establish [redacted] (nominal dollars) as the capital cost to construct the unloading facility, which includes an unloading hopper, track configuration, requisite supporting structures, acquisition of required rights-of-way, roads and underpasses, and environmental and engineering costs.

Q. How did the Company determine an appropriate price range for the hypothetical unloading facility?

A. The Company hired Burns & McDonnell Engineering Company (Burns & McDonnell) in 2012 to develop two cost estimates (using 2012 dollars):

[redacted] included a [redacted] located at the Wyodak plant and [redacted] absent the [redacted].

Q. How does the negotiated cost compare to the study performed by the Burns & McDonnell?

A. The agreed-upon capital costs compare favorably to the cost estimates developed by Burns & McDonnell. The Company and Wyodak Resources agreed to use the lower capital projection, adjusted for inflation.

Q. Does the Company anticipate reaching agreement on the other price components before the Company's rebuttal update in the 2015 TAM?

A. Yes. The Company continues to engage Wyodak Resources on the two remaining contract price components and remains hopeful that an agreement will be reached before the Company files its rebuttal TAM update. If the Company and Wyodak Resources are unable to reach agreement, then the contract allows for either party to seek resolution of the price dispute through binding arbitration.

Jim Bridger

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

A. The price of Black Butte coal delivered to the Jim Bridger plant has increased from [redacted] per ton in the 2014 TAM to [redacted] per ton, an increase of [redacted] per ton. This price increase is principally due to an increase in the Black Butte Free-On-Board (F.O.B.) mine costs associated with the delivery of previously deferred Black Butte contract tonnage. During the term of the Black Butte coal supply agreement, the Jim Bridger plant owners had a contractual right to defer up to

250,000 tons of coal annually. The 2015 TAM reflects delivery of previously deferred tonnage at contract specified pricing.

[redacted]. The actual calculation is included in my workpapers.

Dave Johnston

Q. Does the 2015 TAM reflect an increase in Dave Johnston generating plant coal supply costs?

A. Yes. Dave Johnston plant coal costs have increased by only [redacted] compared to the 2014 TAM. Rail rates increased by approximately [redacted]; coal prices decreased by approximately [redacted] primarily due to a new coal supply agreement with Western Fuels Dry Fork mine and current forward pricing for Powder River Basin 8400 Btu coal.

Q. What are the coal supply arrangements for Dave Johnston in the 2015 TAM?

A. The Company executed a three-year coal supply agreement for the purchase of Dry Fork mine coal from Western Fuels through 2016. Western Fuels is contracted to provided [redacted] tons in 2015; the Company intends to solicit additional multi-year coal supplies for the Dave Johnston plant through a request for proposals during the second quarter of 2014. The coal price for Dave Johnston's open position in the 2015 TAM reflects the forward price for Powder River Basin 8400 Btu coal per ICAP Energy LLC's weekly assessment of coal prices as of [redacted]. The Company plans to update both rail rates and spot market supply costs in the Company's rebuttal update.

Coal Supply Agreements for the Utah Plants

Q. Which non-affiliated mines currently supply coal to the Utah plants?

A. The Company has a diversified portfolio of multi-year coal supply agreements with Bowie's Sufco mine (Sufco), Utah American Energy's West Ridge mine (West Ridge), and Rhino Energy's Castle Valley mine (Castle Valley).

Q. Have prices for coal supply to the Utah plants changed from levels reflected in the 2014 TAM?

A. Yes. Collectively, purchased coal and transportation costs for the Utah plants decrease by approximately [redacted]. The decrease is primarily associated with a price reduction for Castle Valley coal resulting from a January 2015 contract price re-opener, an expected reduction in price and tonnage for West Ridge coal, a decrease in transportation expense, and an increase in Sufco tonnage.

Q. Please discuss the coal supply arrangements with Castle Valley, West Ridge, and Sufco.

A. Under a long-term coal supply agreement, Castle Valley is required to supply [redacted] tons of coal annually through 2017 for the Company's Utah plants. The contract provides fixed pricing through 2014; beginning January 2015, the price is determined through a price re-opener subject a collar. The Castle Valley F.O.B. mine price is projected to decrease from [redacted] per ton in the 2014 TAM to [redacted] per ton, the contract floor, in the 2015 TAM.

The Company's current agreement with the West Ridge mine expires at the end of 2014, and the Company is currently in negotiations with Utah American Energy to extend the coal supply agreement, albeit at reduced volumes and lower prices. The 2015 TAM assumes approximately [redacted] tons of West Ridge coal is purchased at a F.O.B. mine price of [redacted] per ton, compared to the 2014 TAM of [redacted] tons at [redacted] per ton, a reduction of [redacted] per ton.

To offset the decrease in West Ridge coal purchases, the 2015 TAM reflects an increase of Sufco purchases, from [redacted] tons in the 2014 TAM to [redacted] tons. Sufco coal is purchased [redacted], resulting in ratepayer benefits from [redacted] costs associated with the approximate [redacted] increase in Sufco tonnage. The Company's rebuttal update will include changes to reflect ongoing negotiations with the Utah coal suppliers.

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 long-term coal supply agreement with Peabody's Lee Ranch and El Segundo mine complex through 2024, which includes two price re-openers: January 1, 2013, and January 1, 2018.

Q. In reply testimony in the 2014 TAM, you testified that the negotiations between the Cholla plant owners and Peabody were ongoing. Have the parties reached agreement on the price re-opener?

A. Yes, the Cholla plant owners and Peabody reached agreement in December 2013.

The agreement includes a January 2013 clean coal price, meaning that the contract price excludes royalties and taxes, of [redacted] per ton, with quarterly changes reflecting changes in producer and consumer price indices.

Q. What price has the Company assumed for the Cholla coal supply in the 2015 TAM?

A. With quarterly escalation and de-escalation based on producer and consumer price indices, the average clean coal price under the new agreement is projected to increase to from the [redacted] per ton price assumed in the 2014 TAM to [redacted] per ton in the 2015 TAM, or [redacted] per ton. Including royalties, taxes and transportation, the Company forecasts that delivered coal prices will increase from [redacted] per ton in the 2014 TAM to [redacted] per ton in the current TAM, or [redacted] per ton.

Hayden

Q. Has the Hayden plant's coal cost changed from the 2014 TAM?

A. Yes, delivered coal prices have increased slightly from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM, an increase of [redacted] per ton or [redacted]. The contract price adjusts with changes in producer and consumer price indices.

Colstrip

Q. Please explain the increase in coal fuel expense for Colstrip in the 2015 TAM.

A. Coal prices for the Colstrip plant have increased from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM, or [redacted] per ton. Colstrip costs 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 increase in 2015 is primarily attributable to an increase in Rosebud's variable production cost.

CAPTIVE MINE COAL COSTS

Q. Please explain the changes associated with the captive mines.

A. Bridger Coal Company mine costs have increased from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM, or by [redacted] per ton. Deer Creek mine production costs have decreased from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM, but increased on a per million-British-thermal-unit (MMBtu) basis due to lower heat content. Trapper mine costs have increased from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM, or [redacted] per ton. Confidential Table 4 below shows the effect of these changes on captive mine coal fuel expense in the 2015 TAM compared to the 2014 TAM.

Table 4: Captive Mine Cost Variances

[redacted]

Q. In Order No. 13-387, the Commission ordered the Company to remove 50 percent of annual incentive plan awards from rates.[3] Did the Company remove all management overtime and 50 percent of annual incentive plan (AIP) awards from Bridger Coal Company and Deer Creek costs in this proceeding?

A. Yes. In the 2015 TAM, the Company reduced Bridger Coal Company costs by approximately $1.2 million (PacifiCorp share) and Deer Creek costs by approximately $0.5 million to reflect removal of management overtime, fines and citations, and 50 percent of AIP.

Bridger Coal Company

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

A. Bridger Coal Company costs increased from the 2014 TAM by approximately [redacted]. Bridger Coal Company costs increased from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM, or by [redacted] per ton or [redacted]. A slight decrease in heat content of coal from the Bridger Coal Company accounts for [redacted] of the increase, and changes in volume account for the remaining [redacted].

Q. Have Bridger Coal Company's production levels changed?

A. Yes, as reflected in confidential Table 5 below, Bridger Coal Company's production has increased from [redacted] tons in the 2014 TAM to [redacted] tons in the 2015 TAM, and Bridger Coal Company deliveries have increased from [redacted] tons to [redacted] tons. The increase in Bridger Coal Company

[3] Order 13-387 at 8.

deliveries corresponds with [redacted].

Table 5: Bridger Coal Production

[redacted]

Q. Please explain the decrease in production from the Bridger Coal Company's underground mine.

A. The decrease in coal production reflects both the shortening of longwall panels due to roof control issues and an additional longwall move in 2015. Typically, there are two longwall moves in a calendar year; in 2015 there will be three. The third longwall move results in a loss of longwall production for approximately 22 days.

Q. Please describe the major drivers of the increase in cost of Bridger Coal Company deliveries to the Bridger plant.

A. In addition to the cost impact of reduced coal production from the underground mine, there are two other primary drivers for the Bridger Coal Company cost increase: (1) a significant reduction in final reclamation activity; and (2) increased royalty and production tax expense.

Q. How much of the [redacted] increase is attributable to the difference between coal production and coal deliveries at the Bridger Coal Company's surface and underground mines between 2014 and 2015?

A. Approximately [redacted] or [redacted] can be attributed to changes in Bridger

Coal Company's coal production and coal deliveries. The 2014 TAM reflected an increase to the underground mine inventory levels of 39,175 tons and an increase to the surface mine inventory levels of 6,382 tons. The 2015 TAM reflects a projected decrease in underground inventory levels of 311,694 tons and a projected decrease in surface inventory levels of 171,800 tons. The decrease in inventory levels in the 2015 TAM results in approximately [redacted] (total Bridger Coal Company) being credited to coal inventory and debited to coal expense. In the 2014 TAM, approximately [redacted] (total Bridger Coal Company) was credited to coal expense and debited to mine inventory.

Q. Will Bridger Coal Company perform the same level of final reclamation in the 2015 TAM as the 2014 TAM?

A. No. The cash operating costs associated with actual final reclamation activity will decrease from $16.1 million in the 2014 TAM to $11.0 million (total Bridger Coal Company) in the 2015 TAM. The reduction in final reclamation includes a decrease in actual final reclamation, measured in millions of cubic yards, from 6.6 in the 2014 TAM to 5.7 in 2015. Since the cash operating costs associated with final reclamation activity are debited against the final reclamation liability, the decrease in final reclamation volume results in a reduction in operating costs charged to the final reclamation and a corresponding increase in Bridger Coal Company's mine operating costs.

Q. Do the above cost increases affect Bridger Coal Company's royalty expenses?

A. Yes. Average royalties and production taxes have increased from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM. The Company's royalty obligations for coal production from federal and states leases are determined by adding a return on net mine investment to actual mine operating costs. Production taxes are assessed based on third-party coal supplies to Jim Bridger plant.

Q. How do Bridger Coal Company costs compare to the Company's other supply options for the Jim Bridger plant?

A. The delivered cost of coal from Bridger Coal Company is [redacted] per ton in the 2015 TAM, which is comparable to the forecasted Black Butte cost of [redacted] per ton and [redacted].

Deer Creek Mine

Q. Please describe the [redacted] million increase related to Deer Creek mine coal deliveries.

A. Deer Creek mine production costs are projected to decrease from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM, but increase from [redacted] per MMBtu to [redacted] per MMBtu. Reduced post-retirement expense, based on actuarial studies prepared by Towers Watson in 2013, is the primary driver of the lower production costs.

Q. Why are production costs increasing per MMBtu but decreasing per ton?

A. Deer Creek's heat content is projected to decrease from [redacted].

Deer Creek's ash content typically ranges from 12 percent to 14 percent.

Q. Are there other factors besides Deer Creek's reduced heat content that contribute to the overall [redacted] in 2015?

A. Yes, approximately [redacted] of the increase is associated with transfers of Deer Creek coal from the prep plant to the Hunter plant. A portion of Deer Creek's coal production is located at the prep plant, which is located adjacent to the Hunter plant. Deer Creek coal located at the prep plant is subsequently blended with other coals to meet Hunter plant coal quality targets. Coal deliveries from the prep plant to the Hunter plant are made based on the weighted average of coal inventory by source. [redacted].

Q. How do Deer Creek mine costs compare to the Company's other Utah supplies?

A. Deer Creek mine costs compare favorably to the Company's other Utah supplies. The majority of Deer Creek's coal production is delivered to the Huntington plant. In the current test period, the delivered cost of Deer Creek coal to the Huntington plant, net of transfers to the Hunter plant and prep plant, is [redacted] per MMBtu. In comparison, the delivered cost of [redacted] coal to the Huntington plant averages [redacted] per MMBtu in the 2015 TAM.

Trapper Mine

Q. Have Trapper mine costs changed from the 2014 TAM?

A. Yes. Trapper mine costs have increased from [redacted] per ton in the 2014 TAM to [redacted] per ton in the 2015 TAM, or by [redacted] per ton. This increase is primarily attributable to higher stripping costs.

Q. How does the Company's Trapper mine compare to other alternatives?

A. Trapper remains the least-cost fuel supply in Colorado. Trapper's costs in the 2015 TAM are roughly [redacted] per ton less than the delivered price of Colowyo coal to the Craig plant and approximately [redacted] per ton less than the delivered coal price of Twentymile coal to the Hayden plant.

Q. Please summarize the benefits of the Company's coal supply strategy.

A. Customers have significantly benefited from the Company's diversified fueling strategy. This strategy relies on fixed contracts, indexed contracts, and affiliate-owned coal mines to meet the fuel needs of its coal-fired generating plants. While coal costs have increased in this case as a result of various factors, the Company's strategy has resulted in a long-term, stable, and low-cost supply of coal for its customers.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE ___
Exhibit PAC/201
Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Cindy A. Crane

PacifiCorp Compliance Proposal for Periodic Fuel Supply Plans for PacifiCorp's Affiliate Mines

April 2014

PACIFICORP COMPLIANCE PROPOSAL—ORDER NO. 13-387
PERIODIC FUEL SUPPLY PLANS FOR PACIFICORP'S AFFILIATE MINES

A. Background

PacifiCorp is a co-owner of the Jim Bridger plant in Wyoming. The Jim Bridger plant obtains coal supply from the Bridger Coal Company (BCC), which is co-owned by PacifiCorp.[1] PacifiCorp owns the Huntington and Hunter plants in Utah. These plants obtain coal supply from the Deer Creek Mine, owned by Energy West Mining Company (EWMC). EWMC is a wholly owned subsidiary of PacifiCorp. Collectively, BCC and EWMC are referred to as "captive coal" mines. For regulatory purposes, PacifiCorp's captive coal mines are consolidated for reporting and ratemaking on PacifiCorp's books.[2] The Commission has approved the coal supply agreements between PacifiCorp and BCC and PacifiCorp and EWMC under the Commission's transfer pricing rule, OAR 860-027-0048.[3] The Commission conditioned this approval upon the right to review the coal supply agreements for reasonableness in subsequent rate proceedings and the requirement that the Company notify the Commission of any substantive changes to the coal supply agreements, including material changes in cost.

In Order No. 13-387 in PacifiCorp's 2014 Transition Adjustment Mechanism (TAM), the Commission resolved a challenge to Jim Bridger's fuel supply costs by adopting a proposal to facilitate implementing prudence and affiliated interest standards for PacifiCorp's captive mines in future rate cases.[4] The proposal, which was endorsed by PacifiCorp, Staff, and CUB, contemplates PacifiCorp's preparation of periodic fuel supply plans that compare affiliate fuel supply to alternative fuel supply options, including market alternatives. PacifiCorp has prepared this compliance proposal in response to Order No. 13-387.

B. Long-Term Fuel Supply Plans

1. **Purpose of Long-Term Fuel Supply Plans**. The purpose of the long-term fuel supply plan for plants fueled by coal from captive coal mines is to demonstrate that the fuel supplies are "fair, just, and reasonable,"[5] and satisfy the Commission's prudence and affiliate interest standards. The long-term fuel supply plans recognize

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[1] The Bridger Coal Company and the Jim Bridger Plant are jointly owned and fuel supply and/or mining operations decisions must be made jointly.
[2] *In the Matter of Pacific Power & Light Company*, Docket No. UE 21, Order No. 84-898 (Nov. 14, 1984); *In the Matter of Idaho Power Company*, Docket No. UI 107, Order No. 91-567 at 4 (Apr. 29, 1991).
[3] *In the Matter of PacifiCorp*, Docket No. UI 189, Order No. 01-472 at 2 (June 12, 2001); *In the Matter of Idaho Power Company*, Docket No. UI 107, Order No. 91-567 at 4 (Apr. 29, 1991); *In the Matter of the Application of Pacific Power & Light Company for an Order Authorizing It to Enter into Agreements with Energy West Company*, Docket No. UI 105, Order No. 91-513 (Apr. 12, 1991).
[4] *In the Matter of PacifiCorp d/b/a Pacific Power 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 6-7 (Oct. 28, 2013).
[5] *Id*. at 6.

that, given the nature of coal mining operations, a multi-year assessment of coal supply costs is more appropriate than an annual review.[6]

2. **Contents of Long-Term Fuel Supply Plans.** PacifiCorp will prepare long-term fuel supply plans to address the economics of continued coal supply from BCC for the Jim Bridger plant and from EWMC to the Huntington and Hunter plants. The form and content of the fuel supply plans may vary from year to year, but the plans will always retain the objective of determining the least-cost, least-risk coal supply. The long-term fuel supply plans will:

    - Use best available data to determine the least-cost, least-risk coal supplies for the plants;
    - Review fueling options for the plants and prepare least-cost mine plans for the key options;
    - Review data on market costs for alternative coal supplies and transportation and the costs associated with plant modifications necessary for alternative fuel supplies; and
    - Review and compare fuel supply options with sensitivities.

3. **Initial Fuel Supply Plans for Jim Bridger, Huntington and Hunter.** PacifiCorp will file the first long-term fuel supply plans for the Jim Bridger, Huntington and Hunter plants in 2015 in a separate docket subject to the Commission's Open Meetings decision-making process (similar to other utility planning dockets).

4. **Future Fuel Supply Plans.** PacifiCorp will update its long-term fuel supply plans once every five years. PacifiCorp will update the plans more often as necessary to address major milestones in coal supply cycles, such as the expiration of third party-coal supply arrangements, major capital investments in the affiliate coal mines, or potential acquisition of new reserves.

5. **Confidential Material.** The long-term fuel supply plans will contain significant confidential information and will require confidential handling. PacifiCorp will request entry of an ongoing protective order for its long-term fuel supply plan dockets, similar to that applicable to TAM proceedings under Order No. 10-069 in docket UE 216.[7]

[6] *Id*. at 15 (Commissioner Savage, concurring).
[7] *In the Matter of PacifiCorp, dba Pacific Power 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-069 (Feb. 25, 2010).

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

April 2014

DIRECT TESTIMONY OF JUDITH M. RIDENOUR

TABLE OF CONTENTS

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 & 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 designs 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 in this proceeding?

A. I present the Company's proposed rate spread, rates, and revised tariff pages for the 2015 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) and the TAM adjustment for Other Revenues 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 rate design test period for this TAM?

A. In accordance with the TAM Guidelines adopted in Order No. 09-274, because this TAM is filed on a stand-alone basis without a concurrent general rate case, the rate design test year for the TAM is the forecast test year during which the Schedule 201 rates will be effective, which is the 12 months ending December 31, 2015.

Q. How have the proposed NPC been allocated to the rate schedule classes?

A. Consistent with the TAM Guidelines, the proposed NPC have been allocated to the customer classes as agreed in the stipulation from the Company's last general rate case, docket UE 263, which was approved in Order No. 13-474 (UE 263 Stipulation). Paragraph 18 of the UE 263 Stipulation states that the stipulating parties agree to use the "applicable functionalized revenue requirement allocation factors presented on page 4 of Exhibit B [to the UE 263 Stipulation] as the rate spread allocation factors for rate changes until the Commission approves new functionalized revenue requirement allocation factors in a subsequent general rate case filing." The UE 263 Stipulation also lists specific cases to which this rate spread agreement applies, including the Company's 2015 TAM filing. The proposed rate spread in this case is therefore based on the generation allocation factors set forth in Exhibit B to the UE 263 Stipulation. The generation allocation factors and the spread of the proposed NPC to the customer classes are shown on page one of Exhibit PAC/301.

Q. Have you prepared an exhibit showing the present and proposed Schedule 201 rates and revenues?

A. Yes. Pages two and three of Exhibit PAC/301 show the present and proposed Schedule 201 rates and revenues based on the Oregon-allocated forecast NPC identified by Mr. Dickman. As explained by Mr. Dickman, forecast NPC is subject to updates throughout the proceeding.

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 amount related to Other Revenues associated with this TAM filing?

A. The Company's Schedule 205, TAM Adjustment for Other Revenues, is used to collect or distribute the adjustment related to Other Revenues in a stand-alone TAM filing. Rates for this tariff are presently zero. The proposed rate spread and rate design of Schedule 205, TAM Adjustment for Other Revenues, parallels the generation based rate spread and rate design of Schedule 201 for NPC as described above, consistent with past treatment of this adjustment.

Q. Have you prepared an exhibit showing proposed Schedule 205 rates and revenues?

A. Yes. Pages four and five of Exhibit PAC/301 show the proposed Schedule 205 rates and revenues.

Q. Please describe Exhibit PAC/302.

A. Exhibit PAC/302 contains the proposed revised Schedule 201, Net Power Costs, Cost-Based Supply Service, and Schedule 205, TAM Adjustment for Other Revenues.

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 tariff schedules 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 effects of the changes proposed in this filing?

A. The overall proposed effect is a rate increase of 1.5 percent on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/303 shows the estimated effect of the Company’s proposed prices by Delivery Service schedule both exclusive (base) and inclusive (net) of 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. Have you prepared 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/303, 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 $1.84.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE ___
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 2014

PACIFIC POWER
STATE OF OREGON
Functionalized Net Power Cost Revenue Requirement
Forecast 12 Months Ending December 31, 2015
Dollars in Thousands

Line	Description	Total	(A) Residential (sec)	(B) General Service Sch 23 (sec)	(C) General Service Sch 23 (pri)	(D) General Service Sch 28 (sec)	(E) General Service Sch 28 (pri)	(F) General Service Sch 30 (sec)	(G) General Service Sch 30 (pri)	(H) Large Power Service Sch 48T (sec)	(I) Large Power Service Sch 48T (pri)	(J) Large Power Service Sch 48T (trn)	(K) Irrigation Sch 41	(L) Street Lgt. Sch 51, 53, 54
1														
2														
3	Net Power Cost Revenue Requirement	$378,255												
4	Net Power Cost Collection for Schedules not included in COS Study*	$2,003												
5	Net Power Cost for Schedules Included in COS Study	$376,252												
6														
7														
8	Generation Allocation Factors from GRC†	100.00%	42.38%	8.58%	0.01%	15.79%	0.14%	9.46%	0.68%	4.35%	11.11%	5.58%	1.78%	0.12%
9														
10														
11	**Functionalized Net Power Cost Revenue Requirement- (Target)**	**$376,252**	**$159,472**	**$32,301**	**$32**	**$59,424**	**$530**	**$35,583**	**$2,575**	**$16,359**	**$41,810**	**$21,002**	**$6,711**	**$453**
12														
13														

† Generation rate spread allocation factors approved in UE 263.

*Revenues by rate schedule as follow:

Schedule 47 Primary	$1,057
Schedule 47 Transmission	$439
Schedule 15	$213
Schedule 50	$167
Schedule 51 (partial)	$241
Schedule 52	$13
Employee Discount	($128)
Total not in study	$2,003

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2015

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Rates	Revenues
Schedule 4, Residential					
First Block kWh (0-1,000)	3,883,205,889	2.567 ¢	$99,681,895	2.771 ¢	$107,603,635
Second Block kWh (> 1,000)	1,369,857,893	3.506 ¢	$48,027,218	3.785 ¢	$51,849,121
	5,253,063,782		$147,709,113		$159,452,756
				Change	$11,743,643
Employee Discount					
First Block kWh (0-1,000)	11,224,236	2.567 ¢	$288,126	2.771 ¢	$311,024
Second Block kWh (> 1,000)	5,284,001	3.506 ¢	$185,257	3.785 ¢	$199,999
	16,508,237		$473,383		$511,023
Discount			-$118,346		-$127,756
				Change	-$9,410
Schedule 23, Small General Service					
Secondary Voltage					
1st 3,000 kWh, per kWh	858,905,405	2.956 ¢	$25,389,244	3.069 ¢	$26,359,807
All additional kWh, per kWh	261,095,125	2.192 ¢	$5,723,205	2.276 ¢	$5,942,525
	1,120,000,530		$31,112,449		$32,302,332
				Change	$1,189,883
Primary Voltage					
1st 3,000 kWh, per kWh	793,337	2.863 ¢	$22,713	2.972 ¢	$23,578
All additional kWh, per kWh	351,760	2.125 ¢	$7,475	2.206 ¢	$7,760
	1,145,097		$30,188		$31,338
				Change	$1,150
Schedule 28, General Service 31-200kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	1,417,022,170	2.878 ¢	$40,781,898	3.002 ¢	$42,539,006
All additional kWh, per kWh	578,403,411	2.799 ¢	$16,189,511	2.920 ¢	$16,889,380
	1,995,425,581		$56,971,409		$59,428,386
				Change	$2,456,977
Primary Voltage					
1st 20,000 kWh, per kWh	9,729,736	2.744 ¢	$266,984	2.890 ¢	$281,189
All additional kWh, per kWh	8,862,021	2.670 ¢	$236,616	2.812 ¢	$249,200
	18,591,757		$503,600		$530,389
				Change	$26,789
Schedule 30, General Service 201-999kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	181,232,803	3.056 ¢	$5,538,474	3.209 ¢	$5,815,761
All additional kWh, per kWh	1,069,918,078	2.650 ¢	$28,352,829	2.782 ¢	$29,765,121
	1,251,150,881		$33,891,303		$35,580,882
				Change	$1,689,579
Primary Voltage					
1st 20,000 kWh, per kWh	12,315,369	3.020 ¢	$371,924	3.173 ¢	$390,767
All additional kWh, per kWh	79,611,926	2.611 ¢	$2,078,667	2.743 ¢	$2,183,755
	91,927,295		$2,450,591		$2,574,522
				Change	$123,931
Schedule 41, Agricultural Pumping Service					
Secondary Voltage					
Winter, 1st 100 kWh/kW, per kWh	2,801,050	4.015 ¢	$112,462	4.287 ¢	$120,081
Winter, All additional kWh, per kWh	2,404,049	2.735 ¢	$65,751	2.920 ¢	$70,198
Summer, All kWh, per kWh	222,923,263	2.735 ¢	$6,096,951	2.920 ¢	$6,509,359
	228,128,362		$6,275,164		$6,699,638
				Change	$424,474
Primary Voltage					
Winter, 1st 100 kWh/kW, per kWh	9,461	3.888 ¢	$368	4.151 ¢	$393
Winter, All additional kWh, per kWh	54,112	2.649 ¢	$1,433	2.828 ¢	$1,530
Summer, All kWh, per kWh	336,328	2.649 ¢	$8,909	2.828 ¢	$9,511
	399,901		$10,710		$11,434
				Change	$724
Schedule 47, Large General Service, Partial Requirements 1,000kW and over					
Primary Voltage					
On-Peak, per on-peak kWh	29,898,944	2.612 ¢	$780,960	2.624 ¢	$784,548
Off-Peak, per off-peak kWh	10,575,978	2.562 ¢	$270,957	2.574 ¢	$272,226
	40,474,922		$1,051,917		$1,056,774
				Change	$4,857
Transmission Voltage					
On-Peak, per on-peak kWh	9,154,521	2.422 ¢	$221,722	2.464 ¢	$225,567
Off-Peak, per off-peak kWh	8,827,144	2.372 ¢	$209,380	2.414 ¢	$213,087
	17,981,665		$431,102		$438,654
				Change	$7,552

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2015

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Rates	Revenues
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
On-Peak, per on-peak kWh	374,571,539	2.713 ¢	$10,162,126	2.830 ¢	$10,600,375
Off-Peak, per off-peak kWh	207,227,176	2.663 ¢	$5,518,460	2.780 ¢	$5,760,915
	581,798,715		$15,680,586		$16,361,290
				Change	$680,704
Primary Voltage					
On-Peak, per on-peak kWh	989,936,084	2.612 ¢	$25,857,131	2.624 ¢	$25,975,923
Off-Peak, per off-peak kWh	615,177,886	2.562 ¢	$15,760,857	2.574 ¢	$15,834,679
	1,605,113,970		$41,617,988		$41,810,602
				Change	$192,614
Transmission Voltage					
On-Peak, per on-peak kWh	489,470,136	2.422 ¢	$11,854,967	2.464 ¢	$12,060,544
Off-Peak, per off-peak kWh	370,356,398	2.372 ¢	$8,784,854	2.414 ¢	$8,940,403
	859,826,534		$20,639,821		$21,000,947
				Change	$361,126
Schedule 15, Outdoor Area Lighting Service					
Secondary Voltage					
All kWh, per kWh	9,214,471	2.191 ¢	$202,223	2.314 ¢	$213,326
	9,214,471		$202,223		$213,326
				Change	$11,104
Schedule 50, Mercury Vapor Street Lighting Service					
Secondary Voltage					
All kWh, per kWh	8,768,231	1.801 ¢	$158,050	1.902 ¢	$167,147
	8,768,231		$158,050		$167,147
				Change	$9,098
Schedule 51, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	19,318,686	2.843 ¢	$549,189	3.002 ¢	$579,563
	19,318,686		$549,189		$579,563
				Change	$30,374
Schedule 52, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	564,686	2.178 ¢	$12,299	2.300 ¢	$12,988
	564,686		$12,299		$12,988
				Change	$689
Schedule 53, Street Lighting Service, Consumer-Owned System					
Secondary Voltage					
All kWh, per kWh	9,518,024	0.929 ¢	$88,422	0.981 ¢	$93,372
	9,518,024		$88,422		$93,372
				Change	$4,949
Schedule 54, Recreational Field Lighting					
Secondary Voltage					
All kWh, per kWh	1,245,594	1.602 ¢	$19,954	1.692 ¢	$21,075
	1,245,594		$19,954		$21,075
				Change	$1,121
Total before Employee Discount			**$359,406,078**		**$378,367,416**
Employee Discount			-$118,346		-$127,756
TOTAL	**13,113,658,685**		**$359,287,732**		**$378,239,660**
				Change	**$18,951,928**
Schedule 47 Unscheduled kWh	2,612,565				
Total Forecast kWH	13,116,271,250				

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Revenues
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2015

Rate Schedule	Forecast Energy	Proposed Schedule 205 Rates		Revenues
Schedule 4, Residential				
First Block kWh (0-1,000)	3,883,205,889	-0.005	¢	-$194,160
Second Block kWh (> 1,000)	1,369,857,893	-0.006	¢	-$82,191
	5,253,063,782			-$276,351
Employee Discount				
First Block kWh (0-1,000)	11,224,236	-0.005	¢	-$561
Second Block kWh (> 1,000)	5,284,001	-0.006	¢	-$317
	16,508,237			-$878
Discount				$220
Schedule 23, Small General Service				
Secondary Voltage				
1st 3,000 kWh, per kWh	858,905,405	-0.005	¢	-$42,945
All additional kWh, per kWh	261,095,125	-0.004	¢	-$10,444
	1,120,000,530			-$53,389
Primary Voltage				
1st 3,000 kWh, per kWh	793,337	-0.005	¢	-$40
All additional kWh, per kWh	351,760	-0.004	¢	-$14
	1,145,097			-$54
Schedule 28, General Service 31-200kW				
Secondary Voltage				
1st 20,000 kWh, per kWh	1,417,022,170	-0.005	¢	-$70,851
All additional kWh, per kWh	578,403,411	-0.005	¢	-$28,920
	1,995,425,581			-$99,771
Primary Voltage				
1st 20,000 kWh, per kWh	9,729,736	-0.005	¢	-$486
All additional kWh, per kWh	8,862,021	-0.005	¢	-$443
	18,591,757			-$929
Schedule 30, General Service 201-999kW				
Secondary Voltage				
1st 20,000 kWh, per kWh	181,232,803	-0.005	¢	-$9,062
All additional kWh, per kWh	1,069,918,078	-0.005	¢	-$53,496
	1,251,150,881			-$62,558
Primary Voltage				
1st 20,000 kWh, per kWh	12,315,369	-0.005	¢	-$616
All additional kWh, per kWh	79,611,926	-0.005	¢	-$3,981
	91,927,295			-$4,597
Schedule 41, Agricultural Pumping Service				
Secondary Voltage				
Winter, 1st 100 kWh/kW, per kWh	2,801,050	-0.007	¢	-$196
Winter, All additional kWh, per kWh	2,404,049	-0.005	¢	-$120
Summer, All kWh, per kWh	222,923,263	-0.005	¢	-$11,146
	228,128,362			-$11,462
Primary Voltage				
Winter, 1st 100 kWh/kW, per kWh	9,461	-0.007	¢	-$1
Winter, All additional kWh, per kWh	54,112	-0.005	¢	-$3
Summer, All kWh, per kWh	336,328	-0.005	¢	-$17
	399,901			-$21
Schedule 47, Large General Service, Partial Requirements 1,000kW and over				
Primary Voltage				
On-Peak, per on-peak kWh	29,898,944	-0.004	¢	-$1,196
Off-Peak, per off-peak kWh	10,575,978	-0.004	¢	-$423
	40,474,922			-$1,619
Transmission Voltage				
On-Peak, per on-peak kWh	9,154,521	-0.004	¢	-$366
Off-Peak, per off-peak kWh	8,827,144	-0.004	¢	-$353
	17,981,665			-$719

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Revenues
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2015

		Proposed Schedule 205	
Rate Schedule	Forecast Energy	Rates	Revenues
Schedule 48, Large General Service, 1,000kW and over			
Secondary Voltage			
On-Peak, per on-peak kWh	374,571,539	-0.005 ¢	-$18,729
Off-Peak, per off-peak kWh	207,227,176	-0.005 ¢	-$10,361
	581,798,715		-$29,090
Primary Voltage			
On-Peak, per on-peak kWh	989,936,084	-0.004 ¢	-$39,597
Off-Peak, per off-peak kWh	615,177,886	-0.004 ¢	-$24,607
	1,605,113,970		-$64,204
Transmission Voltage			
On-Peak, per on-peak kWh	489,470,136	-0.004 ¢	-$19,579
Off-Peak, per off-peak kWh	370,356,398	-0.004 ¢	-$14,814
	859,826,534		-$34,393
Schedule 15, Outdoor Area Lighting Service			
Secondary Voltage			
All kWh, per kWh	9,214,471	-0.004 ¢	-$199
	9,214,471		-$199
Schedule 50, Mercury Vapor Street Lighting Service			
Secondary Voltage			
All kWh, per kWh	8,768,231	-0.003 ¢	-$119
	8,768,231		-$119
Schedule 51, Street Lighting Service, Company-Owned System			
Secondary Voltage			
All kWh, per kWh	19,318,686	-0.005 ¢	-$204
	19,318,686		-$204
Schedule 52, Street Lighting Service, Company-Owned System			
Secondary Voltage			
All kWh, per kWh	564,686	-0.004 ¢	-$23
	564,686		-$23
Schedule 53, Street Lighting Service, Consumer-Owned System			
Secondary Voltage			
All kWh, per kWh	9,518,024	-0.002 ¢	-$190
	9,518,024		-$190
Schedule 54, Recreational Field Lighting			
Secondary Voltage			
All kWh, per kWh	1,245,594	-0.003 ¢	-$37
	1,245,594		-$37
Total before Employee Discount			**-$639,929**
Employee Discount			$220
TOTAL	**13,113,658,685**		**-$639,710**
Schedule 47 Unscheduled kWh	2,612,565		
Total Forecast kWH	13,116,271,250		

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariffs

April 2014

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 201

NET POWER COSTS
COST-BASED SUPPLY SERVICE

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 860-038-270, 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	2.771¢			(I)
		> 1000 kWh	3.785¢			(I)
5	Per kWh	0-1000 kWh	2.771¢			(I)
		> 1000 kWh	3.785¢			(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	3.069¢	2.972¢		(I)
	All additional kWh, per kWh	2.276¢	2.206¢		(I)
28	First 20,000 kWh, per kWh	3.002¢	2.890¢		(I)
	All additional kWh, per kWh	2.920¢	2.812¢		(I)
30	First 20,000 kWh, per kWh	3.209¢	3.173¢		(I)
	All additional kWh, per kWh	2.782¢	2.743¢		(I)
41	Winter, first 100 kWh/kW, per kWh	4.287¢	4.151¢		(I)
	Winter, all additional kWh, per kWh	2.920¢	2.828¢		(I)
	Summer, all kWh, per kWh	2.920¢	2.828¢		(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	2.830¢	2.624¢	2.464¢	(I)
	Per kWh, Off-Peak	2.780¢	2.574¢	2.414¢	(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	2.300¢	(I)
	For dusk to midnight operation, per kWh	2.300¢	(I)
54	Per kWh	1.692¢	(I)

15	**Type of Luminaire**	**Nominal Rating**	**Monthly kWh**	**RatePer Luminaire**	
	Mercury Vapor	7,000	76	$ 1.76	(I)
	Mercury Vapor	21,000	172	$ 3.98	(I)
	Mercury Vapor	55,000	412	$ 9.53	(I)
	High Pressure Sodium	5,800	31	$ 0.72	(I)
	High Pressure Sodium	22,000	85	$ 1.97	(I)
	High Pressure Sodium	50,000	176	$ 4.07	(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	$1.45	$3.27	$7.84	(I)
Vertical, per lamp	$1.45	$3.27		(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	$1.45			(I)
On 26-foot poles, vertical, per lamp	$1.45			(I)
On 30-foot poles, horizontal, per lamp		$3.27		(I)
On 30-foot poles, vertical, per lamp		$3.27		(I)
On 33-foot poles, horizontal, per lamp			$7.84	(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	$1.45			(I)
On 26-foot poles, vertical, per lamp	$1.45			(I)
On 30-foot poles, horizontal, per lamp		$3.27		(I)
On 30-foot poles, vertical, per lamp		$3.27		(I)
On 33-foot poles, horizontal, per lamp			$7.84	(I)

51

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
LED	4,000	100 (comp)		$0.57	(I)
LED	6,200	150 (comp)		$0.81	
LED	13,000	250 (comp)		$1.53	
LED	16,800	400 (comp)		$2.07	
High Pressure Sodium	5,800	70	31	$0.93	
High Pressure Sodium	9,500	100	44	$1.32	
High Pressure Sodium	16,000	150	64	$1.92	
High Pressure Sodium	22,000	200	85	$2.55	
High Pressure Sodium	27,500	250	115	$3.45	
High Pressure Sodium	50,000	400	176	$5.28	
Metal Halide	12,000	175	68	$2.04	
Metal Halide	19,500	250	94	$2.82	(I)

53

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.30	(I)
High Pressure Sodium	9,500	100	44	$0.43	
High Pressure Sodium	16,000	150	64	$0.63	
High Pressure Sodium	22,000	200	85	$0.83	
High Pressure Sodium	27,500	250	115	$1.13	
High Pressure Sodium	50,000	400	176	$1.73	
Metal Halide	9,000	100	39	$0.38	
Metal Halide	12,000	175	68	$0.67	
Metal Halide	19,500	250	94	$0.92	
Metal Halide	32,000	400	149	$1.46	
Metal Halide	107,800	1,000	354	$3.47	(I)

Non-Listed Luminaire, per kWh 0.981¢ (I)

(continued)

Purpose

This schedule adjusts rates for Other Revenues as authorized by Order No. 10-363.

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	(0.005)¢			(R)
		> 1000 kWh	(0.006)¢			(R)
5	Per kWh	0-1000 kWh	(0.005)¢			(R)
		> 1000 kWh	(0.006)¢			(R)

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).

Schedule		Secondary	Primary	Transmission	
23, 723	First 3,000 kWh, per kWh	(0.005)¢	(0.005)¢		(R)
	All additional kWh, per kWh	(0.004)¢	(0.004)¢		(R)
28, 728	First 20,000 kWh, per kWh	(0.005)¢	(0.005)¢		(R)
	All additional kWh, per kWh	(0.005)¢	(0.005)¢		(R)
30, 730	First 20,000 kWh, per kWh	(0.005)¢	(0.005)¢		(R)
	All additional kWh, per kWh	(0.005)¢	(0.005)¢		(R)
41, 741	Winter, first 100 kWh/kW, per kWh	(0.007)¢	(0.007)¢		(R)
	Winter, all additional kWh, per kWh	(0.005)¢	(0.005)¢		(R)
	Summer, all kWh, per kWh	(0.005)¢	(0.005)¢		(R)

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)

PACIFIC POWER
A DIVISION OF PACIFICORP

Energy Charge (continued)

Delivery Service Schedule No.		Delivery Voltage Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	(0.005)¢	(0.004)¢	(0.004)¢	(R)
747/748	Per kWh, Off-Peak	(0.005)¢	(0.004)¢	(0.004)¢	(R)

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	(0.004)¢	(R)
	For dusk to midnight operation, per kWh	(0.004)¢	(R)
54,754	Per kWh	(0.003)¢	(R)

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
Mercury Vapor	7,000	76	$0.00	
Mercury Vapor	21,000	172	($0.01)	(R)
Mercury Vapor	55,000	412	($0.02)	(R)
High Pressure Sodium	5,800	31	$0.00	
High Pressure Sodium	22,000	85	$0.00	
High Pressure Sodium	50,000	176	($0.01)	(R)

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	$0.00	($0.01)	($0.01)	(R)
Vertical, per lamp	$0.00	($0.01)		(R)

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	$0.00			
On 26-foot poles, vertical, per lamp	$0.00			
On 30-foot poles, horizontal, per lamp		($0.01)		(R)
On 30-foot poles, vertical, per lamp		($0.01)		(R)
On 33-foot poles, horizontal, per lamp			($0.01)	(R)

(continued)

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	$0.00			
On 26-foot poles, vertical, per lamp	$0.00			
On 30-foot poles, horizontal, per lamp		($0.01)		(R)
On 30-foot poles, vertical, per lamp		($0.01)		(R)
On 33-foot poles, horizontal, per lamp			($0.01)	(R)

51, 751

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
LED	4,000	100 (comp)		$0.00	
LED	6,200	150 (comp)		$0.00	
LED	13,000	250 (comp)		$0.00	
LED	16,800	400 (comp)		$0.00	
High Pressure Sodium	5,800	70	31	$0.00	
High Pressure Sodium	9,500	100	44	$0.00	
High Pressure Sodium	16,000	150	64	$0.00	
High Pressure Sodium	22,000	200	85	$0.00	
High Pressure Sodium	27,500	250	115	($0.01)	(R)
High Pressure Sodium	50,000	400	176	($0.01)	(R)
Metal Halide	12,000	175	68	$0.00	
Metal Halide	19,500	250	94	$0.00	

53, 753

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.00	
High Pressure Sodium	9,500	100	44	$0.00	
High Pressure Sodium	16,000	150	64	$0.00	
High Pressure Sodium	22,000	200	85	$0.00	
High Pressure Sodium	27,500	250	115	$0.00	
High Pressure Sodium	50,000	400	176	$0.00	
Metal Halide	9,000	100	39	$0.00	
Metal Halide	12,000	175	68	$0.00	
Metal Halide	19,500	250	94	$0.00	
Metal Halide	32,000	400	149	$0.00	
Metal Halide	107,800	1,000	354	($0.01)	(R)

Non-Listed Luminaire, per kWh (0.002)¢ (R)

Docket No. UE ___
Exhibit PAC/303
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 2014

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, 2015

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	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	484,343	5,253,064	$581,608	$5,262	$586,870	$593,075	$5,262	$598,337	$11,467	2.0%	$11,467	2.0%	1
2	**Total Residential**		484,343	5,253,064	$581,608	$5,262	$586,870	$593,075	$5,262	$598,337	$11,467	2.0%	$11,467	2.0%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	76,950	1,121,146	$120,156	$5,130	$125,286	$121,294	$5,130	$126,424	$1,138	1.0%	$1,138	0.9%	3
4	Gen. Svc. 31 - 200 kW	28	10,093	2,014,017	$177,864	$3,000	$180,864	$180,249	$3,000	$183,249	$2,385	1.3%	$2,385	1.3%	4
5	Gen. Svc. 201 - 999 kW	30	857	1,343,078	$105,063	$961	$106,024	$106,810	$961	$107,771	$1,747	1.7%	$1,747	1.7%	5
6	Large General Service >= 1,000 kW	48	203	3,046,739	$209,087	($9,638)	$199,449	$210,194	($9,638)	$200,556	$1,107	0.5%	$1,107	0.5%	6
7	Partial Req. Svc. >= 1,000 kW	47	7	61,069	$6,276	($203)	$6,073	$6,286	($203)	$6,083	$10	0.5%	$10	0.5%	7
8	Agricultural Pumping Service	41	7,942	228,528	$25,686	($1,256)	$24,430	$26,099	($1,256)	$24,843	$413	1.6%	$413	1.7%	8
9	**Total Commercial & Industrial**		96,052	7,814,577	$644,132	($2,005)	$642,127	$650,932	($2,005)	$648,927	$6,800	1.1%	$6,800	1.1%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,579	9,214	$1,164	$219	$1,383	$1,174	$219	$1,393	$10	0.9%	$10	0.7%	10
11	Street Lighting Service	50	246	8,768	$956	$194	$1,150	$965	$194	$1,159	$9	0.9%	$9	0.8%	11
12	Street Lighting Service HPS	51	736	19,319	$3,339	$710	$4,049	$3,369	$710	$4,079	$30	0.9%	$30	0.7%	12
13	Street Lighting Service	52	26	565	$73	$13	$86	$73	$13	$86	$0	0.0%	$0	0.0%	13
14	Street Lighting Service	53	249	9,518	$583	$120	$703	$588	$120	$708	$5	0.9%	$5	0.7%	14
15	Recreational Field Lighting	54	105	1,246	$102	$20	$122	$103	$20	$123	$1	1.0%	$1	0.8%	15
16	**Total Public Street Lighting**		7,941	48,630	$6,217	$1,276	$7,493	$6,272	$1,276	$7,548	$55	0.9%	$55	0.7%	16
17	**Total Sales before Emp. Disc. & AGA**		588,336	13,116,271	$1,231,957	$4,533	$1,236,490	$1,250,279	$4,533	$1,254,812	$18,322	1.5%	$18,322	1.5%	17
18	Employee Discount				($452)	($3)	($455)	($461)	($3)	($464)	($9)		($9)		18
19	**Total Sales with Emp. Disc**		588,336	13,116,271	$1,231,505	$4,530	$1,236,035	$1,249,818	$4,530	$1,254,348	$18,313	1.5%	$18,313	1.5%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		588,336	13,116,271	$1,233,944	$4,530	$1,238,474	$1,252,257	$4,530	$1,256,787	$18,313	1.5%	$18,313	1.5%	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	$20.49	$20.69	$0.20	0.98%
200	$30.23	$30.64	$0.41	1.36%
300	$39.98	$40.60	$0.62	1.55%
400	$49.73	$50.55	$0.82	1.65%
500	$59.49	$60.51	$1.02	1.71%
600	$69.22	$70.44	$1.22	1.76%
700	$78.96	$80.40	$1.44	1.82%
800	$88.71	$90.36	$1.65	1.86%
900	**$98.46**	**$100.30**	**$1.84**	**1.87%**
950	$103.34	$105.28	$1.94	1.88%
1,000	$108.21	$110.26	$2.05	1.89%
1,100	$120.53	$122.85	$2.32	1.92%
1,200	$132.83	$135.44	$2.61	1.96%
1,300	$145.15	$148.04	$2.89	1.99%
1,400	$157.46	$160.64	$3.18	2.02%
1,500	$169.78	$173.23	$3.45	2.03%
1,600	$182.07	$185.81	$3.74	2.05%
2,000	$231.32	$236.18	$4.86	2.10%
3,000	$354.43	$362.11	$7.68	2.17%
4,000	$477.54	$488.03	$10.49	2.20%
5,000	$600.66	$613.95	$13.29	2.21%

* 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	$70	$79	$71	$80	0.80%	0.70%
	750	$96	$105	$97	$106	0.87%	0.79%
	1,000	$123	$131	$124	$132	0.91%	0.85%
	1,500	$175	$184	$176	$185	0.96%	0.91%
10	1,000	$123	$131	$124	$132	0.91%	0.85%
	2,000	$227	$236	$229	$238	0.98%	0.95%
	3,000	$332	$340	$335	$344	1.00%	0.98%
	4,000	$420	$429	$424	$433	0.99%	0.97%
20	4,000	$447	$456	$451	$460	0.93%	0.91%
	6,000	$624	$632	$629	$638	0.93%	0.92%
	8,000	$800	$809	$808	$816	0.93%	0.92%
	10,000	$977	$986	$986	$995	0.93%	0.92%
30	9,000	$942	$951	$951	$959	0.88%	0.87%
	12,000	$1,207	$1,216	$1,218	$1,227	0.89%	0.88%
	15,000	$1,472	$1,481	$1,486	$1,494	0.90%	0.89%
	18,000	$1,737	$1,746	$1,753	$1,762	0.90%	0.90%

* 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

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$69	$78	$69	$78	0.78%	0.69%
	750	$94	$103	$95	$104	0.86%	0.78%
	1,000	$120	$129	$121	$130	0.89%	0.83%
	1,500	$171	$179	$172	$181	0.94%	0.90%
10	1,000	$120	$129	$121	$130	0.89%	0.83%
	2,000	$222	$230	$224	$232	0.97%	0.93%
	3,000	$323	$332	$327	$335	0.99%	0.97%
	4,000	$409	$418	$413	$422	0.98%	0.96%
20	4,000	$436	$445	$440	$449	0.92%	0.90%
	6,000	$608	$617	$613	$622	0.92%	0.91%
	8,000	$780	$789	$787	$796	0.92%	0.91%
	10,000	$952	$961	$961	$970	0.92%	0.91%
30	9,000	$919	$928	$927	$936	0.87%	0.86%
	12,000	$1,177	$1,186	$1,187	$1,196	0.88%	0.87%
	15,000	$1,435	$1,444	$1,448	$1,457	0.89%	0.88%
	18,000	$1,693	$1,702	$1,708	$1,717	0.89%	0.89%

* 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 Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
15	3,000	$338	$342	1.09%
	4,500	$447	$452	1.24%
	7,500	$665	$674	1.38%
31	6,200	$678	$685	1.12%
	9,300	$903	$914	1.26%
	15,500	$1,353	$1,372	1.40%
40	8,000	$869	$878	1.13%
	12,000	$1,159	$1,174	1.27%
	20,000	$1,740	$1,764	1.41%
60	12,000	$1,294	$1,309	1.14%
	18,000	$1,730	$1,752	1.28%
	30,000	$2,584	$2,621	1.41%
80	16,000	$1,714	$1,733	1.14%
	24,000	$2,288	$2,317	1.28%
	40,000	$3,423	$3,471	1.41%
100	20,000	$2,133	$2,158	1.15%
	30,000	$2,843	$2,879	1.28%
	50,000	$4,261	$4,322	1.42%
200	40,000	$4,174	$4,222	1.16%
	60,000	$5,593	$5,665	1.29%
	100,000	$8,430	$8,550	1.42%

* 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	$434	$441	1.51%
	6,000	$533	$542	1.64%
	7,500	$632	$642	1.72%
31	9,300	$870	$883	1.55%
	12,400	$1,074	$1,092	1.68%
	15,500	$1,278	$1,301	1.76%
40	12,000	$1,115	$1,132	1.56%
	16,000	$1,378	$1,401	1.69%
	20,000	$1,642	$1,671	1.77%
60	18,000	$1,662	$1,688	1.57%
	24,000	$2,050	$2,085	1.69%
	30,000	$2,436	$2,479	1.77%
80	24,000	$2,195	$2,229	1.58%
	32,000	$2,709	$2,755	1.70%
	40,000	$3,223	$3,281	1.78%
100	30,000	$2,725	$2,768	1.58%
	40,000	$3,368	$3,425	1.70%
	50,000	$4,011	$4,082	1.78%
200	60,000	$5,339	$5,425	1.60%
	80,000	$6,625	$6,739	1.72%
	100,000	$7,911	$8,053	1.79%

* 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	$2,552	$2,583	1.19%
	30,000	$3,124	$3,167	1.39%
	50,000	$4,267	$4,336	1.63%
200	40,000	$4,462	$4,518	1.27%
	60,000	$5,604	$5,687	1.48%
	100,000	$7,890	$8,025	1.71%
300	60,000	$6,541	$6,623	1.27%
	90,000	$8,255	$8,377	1.48%
	150,000	$11,683	$11,884	1.72%
400	80,000	$8,501	$8,610	1.28%
	120,000	$10,787	$10,948	1.50%
	200,000	$15,358	$15,624	1.73%
500	100,000	$10,493	$10,628	1.29%
	150,000	$13,350	$13,550	1.50%
	250,000	$19,064	$19,395	1.74%
600	120,000	$12,484	$12,646	1.29%
	180,000	$15,913	$16,153	1.51%
	300,000	$22,770	$23,166	1.74%
800	160,000	$16,467	$16,681	1.30%
	240,000	$21,039	$21,357	1.51%
	400,000	$30,181	$30,709	1.75%
1000	200,000	$20,450	$20,716	1.30%
	300,000	$26,164	$26,561	1.52%
	500,000	$37,593	$38,251	1.75%

* 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		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$3,065	$3,109	1.42%
	40,000	$3,625	$3,682	1.56%
	50,000	$4,186	$4,255	1.67%
200	60,000	$5,502	$5,585	1.51%
	80,000	$6,623	$6,732	1.65%
	100,000	$7,743	$7,878	1.75%
300	90,000	$8,098	$8,221	1.51%
	120,000	$9,779	$9,941	1.65%
	150,000	$11,460	$11,661	1.75%
400	120,000	$10,600	$10,762	1.52%
	160,000	$12,841	$13,055	1.66%
	200,000	$15,082	$15,348	1.76%
500	150,000	$13,114	$13,315	1.53%
	200,000	$15,916	$16,182	1.67%
	250,000	$18,717	$19,049	1.77%
600	180,000	$15,628	$15,868	1.53%
	240,000	$18,990	$19,308	1.68%
	300,000	$22,352	$22,749	1.78%
800	240,000	$20,657	$20,975	1.54%
	320,000	$25,139	$25,562	1.68%
	400,000	$29,621	$30,149	1.78%
1000	300,000	$25,685	$26,082	1.54%
	400,000	$31,288	$31,815	1.69%
	500,000	$36,891	$37,549	1.78%

* 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	$191	$219	$159	$195	$223	$159	1.94%	2.10%	0.00%
	3,000	$287	$314	$159	$292	$321	$159	1.94%	2.05%	0.00%
	5,000	$478	$505	$159	$487	$516	$159	1.94%	2.01%	0.00%
Three Phase										
20	4,000	$383	$437	$314	$390	$446	$314	1.94%	2.10%	0.00%
	6,000	$574	$628	$314	$585	$641	$314	1.94%	2.05%	0.00%
	10,000	$956	$1,011	$314	$975	$1,031	$314	1.94%	2.01%	0.00%
100	20,000	$1,913	$2,186	$1,354	$1,950	$2,232	$1,354	1.94%	2.10%	0.00%
	30,000	$2,869	$3,142	$1,354	$2,924	$3,207	$1,354	1.94%	2.05%	0.00%
	50,000	$4,781	$5,055	$1,354	$4,874	$5,156	$1,354	1.94%	2.01%	0.00%
300	60,000	$5,738	$6,558	$3,414	$5,849	$6,695	$3,414	1.94%	2.10%	0.00%
	90,000	$8,607	$9,427	$3,414	$8,773	$9,620	$3,414	1.94%	2.05%	0.00%
	150,000	$14,344	$15,164	$3,414	$14,622	$15,469	$3,414	1.94%	2.01%	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	$278	$305	$159	$283	$311	$159	1.93%	2.05%	0.00%
	4,000	$371	$397	$159	$378	$405	$159	1.93%	2.02%	0.00%
	5,000	$464	$490	$159	$472	$500	$159	1.93%	2.00%	0.00%
Three Phase										
20	6,000	$556	$609	$314	$567	$622	$314	1.93%	2.04%	0.00%
	8,000	$742	$795	$314	$756	$811	$314	1.93%	2.02%	0.00%
	10,000	$927	$980	$314	$945	$1,000	$314	1.93%	2.00%	0.00%
100	30,000	$2,781	$3,046	$1,344	$2,835	$3,108	$1,344	1.93%	2.04%	0.00%
	40,000	$3,708	$3,973	$1,344	$3,780	$4,053	$1,344	1.93%	2.02%	0.00%
	50,000	$4,635	$4,900	$1,344	$4,725	$4,998	$1,344	1.93%	2.00%	0.00%
300	90,000	$8,343	$9,139	$3,404	$8,505	$9,325	$3,404	1.93%	2.04%	0.00%
	120,000	$11,124	$11,920	$3,404	$11,340	$12,160	$3,404	1.93%	2.02%	0.00%
	150,000	$13,906	$14,701	$3,404	$14,174	$14,995	$3,404	1.93%	2.00%	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	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$25,522	$25,868	1.36%
	500,000	$36,474	$37,050	1.58%
	650,000	$44,687	$45,437	1.68%
2,000	600,000	$50,596	$51,288	1.37%
	1,000,000	$70,709	$71,863	1.63%
	1,300,000	$86,450	$87,949	1.73%
6,000	1,800,000	$147,354	$149,430	1.41%
	3,000,000	$210,315	$213,776	1.65%
	3,900,000	$257,536	$262,035	1.75%
12,000	3,600,000	$293,368	$297,521	1.42%
	6,000,000	$419,291	$426,213	1.65%
	7,800,000	$513,733	$522,731	1.75%

Notes:
On-Peak kWh 64.38%
Off-Peak kWh 35.62%

* 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	$24,358	$24,383	0.10%
	500,000	$34,709	$34,750	0.12%
	650,000	$42,472	$42,525	0.13%
2,000	600,000	$48,227	$48,276	0.10%
	1,000,000	$67,138	$67,221	0.12%
	1,300,000	$81,977	$82,084	0.13%
6,000	1,800,000	$139,844	$139,992	0.11%
	3,000,000	$199,200	$199,447	0.12%
	3,900,000	$243,717	$244,038	0.13%
12,000	3,600,000	$278,318	$278,615	0.11%
	6,000,000	$397,030	$397,525	0.12%
	7,800,000	$486,064	$486,707	0.13%

Notes:

On-Peak kWh	61.67%
Off-Peak kWh	38.33%

* 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	$34,087	$34,283	0.57%
	650,000	$41,258	$41,513	0.62%
2,000	1,000,000	$65,483	$65,874	0.60%
	1,300,000	$79,139	$79,648	0.64%
6,000	3,000,000	$194,408	$195,582	0.60%
	3,900,000	$235,377	$236,904	0.65%
12,000	6,000,000	$386,653	$389,001	0.61%
	7,800,000	$468,591	$471,644	0.65%
50,000	25,000,000	$1,604,204	$1,613,989	0.61%
	32,500,000	$1,945,612	$1,958,333	0.65%

Notes:

On-Peak kWh	56.93%
Off-Peak kWh	43.07%

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